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EMISSIONS ASSESSMENT OF CONVENTIONAL STATIONARY COMBUSTION SYSTEMS: SUMMARY REPORT

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16. ABSTRACT The report gives results of a characterization of multimedia emissions from 39 source categories of conventional stationary combustion systems. In the assessment, existing emissions data were first examined to determine the adequacy of the data base. This was followed by a measurement program to fill identified data gaps. Emissions data obtained from the sampling and analysis program were combined with existing emissions data to provide estimates of emission levels, and to define the need for additional data. Study results indicate that flue gas emissions of NOx, SO_2, and particulate matter from the 39 source categories account for approximately 86, 66, and 36%, respectively, of the emissions of these pollutants from all stationary sources. Additionally, flue gas emissions of sulfates and several trace elements from coal- and oil-fired combustion sources also require further attention. POM compounds in flue gas emissions are mostly naphthalene, phenanthrene, and pyrene. However, dibenz(a,h)anthracene and possibly benzo(a)pyrene, both active carcinogens, were detected at a limited number of coal- and wood-fired sites. Concentrations of iron, magnesium, manganese, nickel, and phosphorus in wastewater streams are at levels that may be of environmental concern. Data on coal fly ash and bottom ash show 11-16 trace elements at potentially harmful levels.

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ABSTRACT

Multimedia emissions from thirty-nine source categories of conventional stationary combustion systems are characterized in this study. In the assessment process, existing emissions data were first examined to determine the adequacy of the data base. This was followed by the conduct of a measurement program to fill the identified data gaps. Emissions data obtained from the sampling and analysis program were combined with existing emissions data to provide estimates of emission levels, and to define the need for additional data.

The results of this study indicate that conventional stationary combustion systems contribute significantly to the nationwide emissions burden. Flue gas emissions of NO_x, SO_2, and particulate matter from the thirty-nine source categories studied account for approximately 86 percent, 66 percent, and 36 percent, respectively, of the emissions of these pollutants from all stationary sources. Additionally, flue gas emissions of sulfates and several trace elements from coal- and oil-fired combustion sources also require further attention. POM compounds in flue gas emissions are mostly naphthalene, phenanthrene, and pyrene. However, dibenz(a,h)anthracene and possibly benzo(a)pyrene, both active carcinogens, were detected at a limited number of coal-fired sites. Also, dibenz(a,h)anthracene, and possibly benzo(a)pyrene and benzo(g,h,i)perylene, another active carcinogen, were detected at one coal-fired and one wood-fired underfeed stoker tested. The possible presence of benzo(a)pyrene in significant amounts was indicated in the emissions of two other wood-fired boilers.

A second major source of air emissions in steam electric plants is vapors and drifts from cooling towers. Air emissions of chlorine, magnesium, phosphorus, and sulfates from mechanical draft cooling towers were found to be comparable to flue gas emissions of these pollutants from oil-fired utility boilers.

Wastewater streams are generated from several operations in steam electric plants, and in industrial and commercial/institutional facilities but to a much

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lesser extent. Overall, concentrations of iron, magnesium, manganese, nickel, and phosphorus are at levels that may be of environmental concern. Average organic levels ranged from 0.01 mg/l for ash pond effluents to 6.0 mg/l for boiler blowdown. Also, no POM compound was detected in wastewater streams.

Data on coal fly ash and bottom ash show that from eleven to sixteen trace elements are present at potentially harmful levels. The only POM compounds detected, however, were naphthalene, alkyl naphthalenes, and other relatively nontoxic compounds.

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1. INTRODUCTION

The combustion of common fuels - coal, oil, gas, and wood - in conventional stationary systems for heating and power generation is one of the largest and most widespread sources of environmental pollution. Combustion of these fuels affects air, water, and land. In a preliminary assessment of the significance of stationary combustion systems as sources of pollution (1), it was estimated that these combustion sources contribute a major portion of the total man-made emissions of nitrogen oxides, sulfur dioxide, and particulate matter. Further, many of the combustion processes and associated pollution control technologies also produce solid wastes, in the form of ash and sludge, that present disposal problems. Leaching of chemical compounds and heavy metals from solid fuel or waste material, as well as direct discharges of wastewater streams, may result in contamination of water resources. Assessment of the environmental impacts is complicated by cross-media and multi-media effects, as pollutants merge with or pass between environmental media. For example, removal of sulfur dioxide and particulate matter from flue gases significantly increases the amount of solid wastes requiring disposal.

The U.S. Environmental Protection Agency (EPA) has long been active in regulating the release of pollutants from stationary conventional combustion processes. The involvement has included characterization of emission streams, research on the health and ecological effects of combustion pollutants, development and demonstration of pollution control technologies, and setting and enforcing of environmental standards. Much of the earlier work on combustion pollutant characterization, however, was focused on the three major air pollutants - sulfur dioxide, nitrogen oxides, and particulate matter - and the subsequent development of control technologies and standards for these pollutants. As a consequence, the early characterization work was limited in scope and did not adequately address the emissions of other potentially hazardous pollutants or the multi-media aspects of combustion emissions.

These observations were confirmed in the preliminary assessment study (1), which identified the inadequate characterization of flue gas emissions of trace elements, sulfates, particulate matter by size fraction, and polycyclic organic matter (POM). In addition, the same study also identified the general inadequacy of the data base characterizing air emissions from cooling towers and coal storage piles, and wastewater effluents and solid wastes from combustion processes.

From the above discussion, it is apparent that much of the data describing pollutant types and quantities released from stationary conventional combustion processes were unavailable. A comprehensive characterization of emissions from these processes, therefore, was needed as a basis for identifying the pollutants of concern, for estimating the total quantities of pollutants emitted, for assessing the impacts of pollutant emissions on health and the environment, and for evaluating the need for control technology development. In response to the need for a comprehensive characterization, the EPA's Industrial Environmental Research Laboratory at Research Triangle Park (IERL-RTP) in North Carolina established the Conventional Combustion Environmental Assessment (CCEA) Program as the primary vehicle for filling the identified data gaps. The component project under which this study was performed is known as the Emissions Assessment of Conventional Combustion Systems (EACCS) project, and the specified objectives of this project are:

- Compilation and evaluation of all available emissions data on pollutants from selected stationary conventional combustion processes.
- Acquisition of needed new emissions data from field tests.
- Characterization of air emissions, wastewater effluents, and solid wastes generated from selected stationary conventional combustion processes, utilizing combined data from existing sources and field tests.
- Determination of additional data needs, including specific areas of data uncertainty.

Because of the comprehensive characterization requirement, the assessment process in this project was based on a critical examination of existing data, followed by a phased sampling approach to fill data gaps. In the first phase, sampling and analysis procedures were used to provide results accurate

to a factor of 3 so that preliminary assessments can be made and problem areas identified. The methodology employed was similar to the Level I sampling and analysis procedures developed under the direction of the Industrial Environmental Research Laboratory of the U.S. Environmental Protection Agency (2), the major addition being that GC/MS analysis for POM was performed on the samples collected in this project. Evaluation of results from the first phase was used to determine all waste stream/pollutant combinations requiring a more detailed and accurate Level II sampling and analysis program. Level II tests were subsequently conducted at a selected number of sites. In terms of major potential benefits, the characterization of combustion source emissions from this project will allow EPA to determine the environmental acceptability of combustion waste streams and pollutants and the need for control of environmentally unacceptable pollutants.

The combustion source types to be assessed in this project were selected because of their relevance to emissions and because they are among the largest, potentially largest, or most numerous (in use) of existing combustion source types. A total of 39 source types were selected for study. Selected source types were classified under the following principal categories:

1) Electricity generation - External combustion
2) Industrial - External combustion
3) Electricity generation and industrial - Internal combustion
4) Commercial/institutional - Space heating/internal combustion
5) Residential - Space heating

These five principal categories were further divided into subcategories based on fuel type, furnace design, and firing method. The subcategorization is needed because of the differences in the emission characteristics of combustion source types.

This document provides an overall summary of the five group/category reports published under the EACCS project. These five group/category reports are:

- Volume I. Gas and Oil-Fired Residential Heating Sources (3).
- Volume II. Internal Combustion Sources (4).

- Volume III. External Combustion Sources for Electricity Generation (5).
- Volume IV. Commercial/Institutional Combustion Sources (6).
- Volume V. Industrial Combustion Sources (7).

These reports present and discuss data evaluation and test results, and provide best estimates of emission factors or discharge stream concentrations for effluents from each of the principal combustion source categories. These emission estimates were derived utilizing combined data from existing information sources and field tests conducted in the current project. Each report also provides estimates of nationwide emissions from the specified combustion source category, and identifies major gaps in emissions data. As such, information contained in the reports can be used for:

- Compilation of emission factors for pollutants and waste streams for which no existing data were available.
- Upgrading of existing emission factors for pollutants and waste streams.
- Performing environmental assessments of conventional stationary combustion sources.
- Determining the nationwide burden of emissions from conventional stationary combustion sources.
- Evaluating the need for control technology development, based on analysis of the environmental impacts of uncontrolled and controlled emissions.
- Planning of future Level II field tests to provide critical data needs.
- Providing input to the development of emission standards.

Combustion system types which were considered in the five group/category reports are indicated in Table 1.

TABLE 1. COMBUSTION SYSTEMS CONSIDERED IN THE STUDY

Combustion Source Type	User Sector			
	Electricity Generation	Industrial	Commercial/ Institutional	Residential
External Combustion				
Coal				
Bituminous				
Pulverized dry	X	X	X	
Pulverized wet	X	X		
Cyclone	X			
All stokers	X	X	X	
Anthracite				
Pulverized dry	X			
All stokers	X		X	
Lignite				
Pulverized dry	X			
Cyclone	X			
All stokers	X			
Petroleum				
Residual oil				
Tangential firing	X			
All other	X	X	X	
Distillate oil				
Tangential firing				
All other		X	X	X
Gas				
Tangential firing	X			
All other	X	X	X	X
Wood				
Stoker		X	X	
Internal Combustion				
Distillate Oil				
Gas turbine	X	X		
Reciprocating engine	X	X	X	
Gas				
Gas turbine	X	X		
Reciprocating engine	X	X	X	

2. ASSESSMENT METHODOLOGY

The assessment method employed in the project involved a critical examination of existing emissions data, followed by the conduct of a measurement program to fill data gaps based on phased sampling and analysis strategy. Data acquired as a result of the measurement program, in combination with the existing data, were further evaluated. Data inadequacies identified at the completion of the project are discussed with respect to the need for additional study.

Specifically, the phased approach to environmental assessment is designed to provide comprehensive emissions information on all process waste streams in a cost effective manner. To achieve this goal, two distinct sampling and analysis levels were employed in the project. Level I utilizes semiquantitative (± a factor of 3) techniques of sample collection and laboratory and field analysis: 1) to provide preliminary emissions data for waste streams and pollutants not adequately characterized; 2) to identify potential problem areas; and 3) to prioritize waste streams and pollutants in those streams for further, more quantitative testing. Using the information from Level I, available resources can be directed toward Level II testing which involves specific quantitative analysis of components of those streams that do contain significant pollutant levels. The data developed at Level II are used to identify control technology needs and to further define the environmental hazards associated with emissions.

3. SOURCE DESCRIPTION

3.1 GAS- AND OIL-FIRED RESIDENTIAL HEATING SOURCES

Residential space heating sources are defined as combustion units with fuel input capacities below 422 MJ/hr (0.4 million Btu/hr) in accordance with recent U.S. Environmental Protection Agency (EPA) sponsored studies. Residential combustion systems consume about 15 percent of the fuel used by conventional stationary combustion systems. The residential sector accounted for about 6800 PJ* of the 1978 estimated fuel consumption total of 45,000 PJ. This source uses primarily gas (58 percent) and oil (38 percent). It is estimated that in 1974 there were about 34,000,000 gas-fired, 13,000,000 oil-fired, 740,000 coal-fired, and 660,000 wood-fired residential space heating systems in the United States.

Heating systems for residential sources are concentrated in areas of high population density such as the Northeast, Midwest, and parts of California. Oil consumption is most heavily concentrated in the northeast with the states of Pennsylvania, New York, New Jersey, Massachusetts, and Connecticut consuming 53 percent of the U.S. total. Only very small amounts of oil are burned in the west and south. Residential gas consumption for space heating is more widely distributed than oil, but is still most heavily concentrated in the upper midwest and northeast. States that account for more than 5 percent of the U.S. total residential gas consumption include Illinois (8.9 percent), New York (8.3 percent), Ohio (8.1 percent), California (7.8 percent), Michigan (7.6 percent), and Pennsylvania (6.0 percent).

Residential gas- and oil-fired space heating equipment is subject to a number of design variations related to burners, combustion chambers, excess air, heating medium, etc. Residential systems generally operate only in an on/off mode with no variation in fuel input rate in contrast to load modulation encountered with larger commercial, industrial, and electric utility systems.

*1 PJ = 10^{15} joules.

Gas-fired systems are inherently less complex and easier to maintain than oil-fired units because the fuel is cleaner and atomization is not required. Residential gas burners use natural aspiration and are very similar in design, whereas several burner designs are used for oil atomization. However, high pressure (~100 psig) atomization burners account for about 90 percent of the total (8). Low pressure and rotary burners are being phased out because of their complexity. Although air pollution control equipment is not available for residential combustion systems, emission reduction measures are being evaluated. The EPA is active in the development and evaluation of residential gas- and oil-fired burners and furnaces.

3.2 INTERNAL COMBUSTION SOURCES

Stationary internal combustion sources for electricity generation and industrial applications are grouped into two categories: gas turbines and reciprocating engines. Gas turbines may be classified into three general types: simple open cycle, regenerative open cycle, and combined cycle. Regenerative type gas turbines constitute only a very small fraction of the total gas turbine population. Emissions from identical gas turbines used in the combined cycle and in the simple cycle are the same. Therefore, only emissions from simple cycles need to be evaluated.

Reciprocating internal combustion engines may be classified into spark and compression ignition (diesel) engines. All distillate oil reciprocating engines are compression ignited, and all gasoline reciprocating engines are spark ignited. Spark ignition gasoline engines have very limited use for electricity generation and industrial application because of their poor part load economy and cost of fuel. Gas reciprocating engines, with the exception of the dual-fuel type, are spark ignited. Gas can only be used in a compression ignition engine if a small amount of diesel fuel is injected into the compressed air/gas mixture to initiate combustion.

The principal application areas for gas turbines and reciprocating engines are: electricity generation, oil and gas transmission, natural gas processing, oil and gas production and exploration. For gas turbines, the total 1978 installed capacity was 50,800 MW for electricity generation and 9,400 MW for industrial applications. For reciprocating engines, the total

1978 installed capacity was 5,300 MW for electricity generation and 19,500 MW for industrial applications.

The current average size of electricity generation gas turbines is approximately 31 MW. As of December 31, 1976, the capacity average age for electricity generation gas turbines was approximately 5 years. Industrial gas turbines were estimated to have an average size of 2.2 MW. For reciprocating engines, the average size unit for electricity generation is 1.9 MW (2,500 HP), and the average size unit for oil and gas transmission is 1.5 MW (2,000 HP). Average age for reciprocating engines is approximately 10 years.

Air pollution control equipment is generally not installed on gas turbines or reciprocating engines. However, there is increasing recognition that water and steam injection are valid techniques for controlling NO_x emissions from gas turbines. In addition, to reduce visible smoke emissions from oil-fueled gas turbines, fuel additives such as soluble compounds of barium, manganese and iron are often employed.

3.3 EXTERNAL COMBUSTION SOURCES FOR ELECTRICITY GENERATION

Stationary external combustion sources for electricity generation can be classified according to the type of fuel used and furnace design. Fuels used in utility boilers include bituminous coal, anthracite coal, lignite coal, residual oil, and natural gas. For coal firing, furnace designs include four major types: pulverized dry bottom, pulverized wet bottom, cyclone, and stokers. The primary methods of firing pulverized coal, residual oil, and natural gas are: tangential firing, front wall firing, and horizontally-opposed firing.

In 1978, the total installed generating capacity for conventional steam plants firing fossil fuels was 401,467 MW. Of the installed generating capacity, 58.1 percent were coal-fired boilers, 25.5 percent were oil-fired boilers, and 16.4 percent were gas-fired boilers. For coal-fired boilers, the pulverized bituminous dry bottom category accounted for over 73 percent of the installed generating capacity. During the 1979-1985 period, generating capacity additions of approximately 80,000 MW are projected for pulverized bituminous dry bottom boilers. The only other major generating capacity additions will be 17,300 MW for pulverized lignite dry bottom boilers. Coal-

fired pulverized wet bottom and cyclone boilers are no longer being sold because of their inability to meet NO_x standards, and coal-fired stokers are being phased out by retirements. The projected 1985 installed generating capacity also shows a small increase in generating capacity for oil-fired utility boilers, and a small decrease in generating capacity for gas-fired utility boilers. By 1985, 66.6 percent of the installed generating capacity for utility boilers will be coal-fired, 20.9 percent will be oil-fired, and only 12.5 percent will be gas-fired.

Fossil fuels consumed by electricity generation external combustion sources in 1978 amounted to 120.4 Tg* of western bituminous coal (2,698 PJ), 316.6 Tg of eastern bituminous and anthracite coal (8,280 PJ), 31.1 Tg of lignite coal (477 PJ), 94.1 x 10^6 m^3 of residual oil (3,830 PJ), and 62.9 x 10^9 m^3 of natural gas (2,399 PJ). From 1978 to 1985, the projected fossil fuel requirements indicate a 47.6 percent increase and 16.4 percent increase in coal and oil consumption, respectively, and a 40.6 percent decrease in natural gas consumption. The increase in coal consumption will be mostly due to significant increases in the consumption of western bituminous (119.0 percent) and lignite coal (113.8 percent). The consumption in eastern bituminous coal is only projected to increase by 20.6 percent during the same time period.

Air, water, and solid waste pollutants are emitted from a number of operations within a steam electric plant. The major source of air emissions is flue gas emissions from stacks. Other sources are emissions from ash handling and storage, fuel handling and storage, and cooling systems in the form of drifts and vapors.

Air pollution control on utility boilers is mainly directed at reducing flue gas emissions of particulates, sulfur dioxide, and nitrogen oxides. For control of particulate emissions, electrostatic precipitators and centrifugal separators are the most common types of devices used.

To reduce emissions of sulfur dioxide to the atmosphere, there are five flue gas desulfurization (FGD) processes sufficiently developed for full-scale commercial application: lime/limestone scrubbing, magnesium oxide scrubbing, sodium carbonate scrubbing, the double-alkali process, and the Wellman-Lord process. By the end of 1978, there were 51 operating FGD systems

*1 Tg = 10^{12} grams.

on utility boilers totalling 17,888 MW in generating capacity, 14,309 MW of which were on bituminous coal-fired boilers and the remaining on lignite coal-fired boilers. On generating capacity basis, 92 percent of the operating FGD systems utilize lime/limestone scrubbing. By 1985, the FGD systems scheduled for operation will increase significantly, to a total representing 52,572 MW in generating capacity.

The primary techniques for reducing NO_x emissions from utility boilers include: low excess air firing (LEA), flue gas recirculation (FGR), off-stoichiometric combustion, reduced air preheat, and burner or furnace modification. Low excess air firing is the only NO_x control on utility boilers that has been implemented on a large scale. The generating capacity of utility boilers equipped with NO_x controls amounted to 43,756 MW in 1978, representing approximately 10.9 percent of the total utility fossil fuel-fired boiler generating capacity.

Water usage in steam electric plants is complex and results in wastewater streams from a number of operations. These include: discharge from once-through cooling systems or blowdown from cooling towers, ash pond overflow, wastewater from wet-scrubber systems, boiler blowdown, wastewater from water treatment processes, chemical cleaning wastes, coal pile runoff, and miscellaneous low volume wastes. The two principal methods of wastewater treatment are controlled release to a waterway, and retention in a holding pond for sedimentation and/or neutralization before controlled release.

Solid wastes are generated in fossil fuel-fired steam electric plants in the form of fly ash, bottom ash, spent scrubber sludge, and water treatment sludges. Disposal of fly ash and bottom ash involves either mechanically conveying the dry ash to a landfill area, or by water sluicing and piping the ash transport water to a settling pond. In ash disposal by water sluicing, an intermediate stage of ash dewatering is sometimes involved, resulting in disposal of the wet ash in landfills. The current trend, however, is away from ash disposal and towards increased ash utilitization. Spent scrubber sludges from nonrecovery FGD systems are currently disposed of by the use of lined and unlined ponds, landfills, and mines, both with and without sludge stabilization. Sludges from water treatment processes are disposed of by

direct discharge to waterways or sewer systems, by transport to settling ponds, and to landfills after dewatering.

3.4 COMMERCIAL/INSTITUTIONAL COMBUSTION SOURCES

The commercial/institutional external combustion sources evaluated in this study were sources used for space heating of trade establishments, health and educational institutions, and government facilities. These application areas are identical to those used by the Department of Energy (DOE) in compiling energy consumption data for the commercial sector (9). Commercial combustion units have also been defined as units with heat inputs ranging from 0.42 to 13.2 GJ/hr (10,11). However, this definition excludes many smaller and larger units used in the commercial/institutional sector. Institutional units especially tend to be appreciably larger than 13.2 GJ/hr and account for almost 20 percent of the commercial/institutional sector fuel consumption (1).

Commercial/institutional fuel consumption for space heating was 5100 PJ in 1978 based on DOE data for total fuel consumption (9) and estimates of the fraction of this fuel used for space heating (12). This consumption value is less than 10 percent of the estimated 1978 national fuel consumption figure of 54,000 PJ, excluding fuel used in the transportation sector (9). Commercial/institutional external combustion sources for space heating primarily use oil (52 percent) and gas (44 percent). Small amounts of coal and wood are also used by the commercial/institutional sector. Internal combustion sources in the commercial/institutional sector, primarily gas- and oil-fired reciprocating engines, are used for pumping municipal water and sewage. Small amounts of fuel may also be used by internal combustion sources for auxiliary power generation.

Heating systems for commercial/institutional sources are concentrated in areas of high population density such as the Northeast, Midwest, and parts of California. Oil consumption is most heavily concentrated in the Northeast with the States of New York, Massachusetts, New Jersey, and Pennsylvania consuming about 25 percent of the U.S. total. Commercial gas consumption for space heating is more widely distributed than oil, but is still most heavily concentrated in the Midwest and Northeast (13).

Commercial/institutional external combustion sources can be sold as either packaged units or boilers to be constructed onsite. Most units in the commercial sector are packaged units. Field-erected units, for the most part, are restricted to larger institutional facilities. Estimates of the total number of commercial external combustion sources have been reported (10,14) and, according to these estimates, there are approximately 1.5 million commercial sources. Most of the smaller units (<13.2 GJ/hr) are cast iron or firetube units, and only 5 percent of these smaller units are of watertube design. Watertube units, however, constitute 100 percent of all units above 50 GJ/hr input (14).

Air pollution control equipment is generally not installed on the smaller commercial external combustion sources, although new burner designs, atomization methods and furnace constructions are being studied to reduce emissions of NO_x and particulates. Burner modulation during periods of fluctuating demand, instead of on/off cycling, also reduces particulate and hydrocarbon emissions from oil-fired sources (11).

3.5 INDUSTRIAL COMBUSTION SOURCES

Stationary external combustion sources used within the industrial sector for electricity generation, production of steam for process heating, and space heating can be classified according to the type of fuel used and furnace and boiler design. Fuels used in industrial combustion systems include bituminous coal, anthracite coal, lignite coal, wood, residual oil, distillate oil, and natural gas. Pulverized dry bottom furnaces and stoker furnaces are the major furnace designs used by the industrial sector for the combustion of bituminous coal. Stoker furnaces predominate for wood-fired combustion sources and for the combustion of lignite and anthracite coals. Although a large percentage of industrial boilers are cast iron systems, these systems constitute only about 7 percent of total industrial boiler capacity. Firetube boilers, in which the combustion gases pass through tubes submerged in water, make up about 24 percent of total industrial capacity. These units generally are smaller than about 21 GJ/hr input capacity. Watertube boilers constitute about 69 percent of the industrial boiler capacity. In a watertube system the combustion gases transfer heat to tubes into which water is fed to be

converted to steam. Boiler systems larger than about 53 GJ/hr input capacity and systems with steam pressures exceeding about 65 kPa are almost exclusively watertube systems.

There are approximately 500,000 industrial boilers in the United States with an estimated capacity of about 4,000 TJ/hr. Natural gas is the primary fuel, accounting for about 63 percent of the total industrial fossil fuel use in 1978, while oil and coal account for about 18 percent and 15 percent, respectively. Wood and other miscellaneous fuels are minor fuel sources. Total fuel consumption by the industrial external combustion sources considered in this study was 8700 PJ/yr in 1978, about 22 percent of total national fuel consumption by the stationary combustion sources studied in this project. The overall growth rate during the 1978-1985 period should be about 3 percent per year. Coal consumption by 1985 could account for 30 percent of industrial fuel use in 1985, if provisions of the National Energy Plan are fully implemented. This increase, however, could be a gross overestimate because of the influence of regulatory actions limiting, for example, sulfur content of the coal fuel.

Air, water, and solid waste pollutants are emitted from many sources constituting an industrial boiler facility. The major source of air emissions is flue gas emissions from stacks. Other potential sources of air emissions depending on the size of the facility and the type of fuel burned, are ash handling and storage, fuel handling and storage, and drifts and vapors from cooling systems. Wastewater emission streams and sources of solid wastes vary in number and volume, depending again on facility size and type of fuel burned. Emphasis in this study was placed solely on air emissions from stacks, with the exception of the characterization of bottom ash and fly ash from the wood-fired systems tested in this study.

Air pollution control on industrial boilers is mainly directed at reducing particulate flue gas emissions from solid fuel-fired sources. The estimated overall efficiency of particulate removal in the industrial sector, based on data in the National Emissions Data System (NEDS), is 81 percent for pulverized units and 53 percent for stokers. Application of control measures for SO_x and NO_x is not extensive in the industrial sector, but will increase with the promulgation of regulations for control of such emissions from industrial boilers.

4. EXISTING EMISSIONS DATA BASE

A major task in this project has been the identification of gaps and inadequacies in the existing data base. Decisions as to the adequacy of the data base were made using criteria developed by considering both the reliability and variability of the data. Estimated environmental risks associated with the emission of each pollutant were also considered in the determination of the need for, and extent of, the sampling and analysis program.

4.1 GAS- AND OIL-FIRED RESIDENTIAL HEATING SOURCES

The sources of emissions data for residential gas- and oil-fired systems are limited at the present time to early data used to generate EPA emission factors and more recent data developed by EPA contractors for criteria pollutants. For gas-fired systems, the existing data base for sulfur dioxide (SO_2), nitrogen oxides (NO_x), total hydrocarbons (HC), and carbon monoxide (CO) emissions was adequate. However, the existing data base for particulate and specific organic emissions was inadequate. For oil-fired systems, the existing emissions data base for particulate, SO_2, NO_x, HC, and CO was adequate, but inadequate for SO_3, particulate sulfate, trace element, and organic emissions.

4.2 INTERNAL COMBUSTION SOURCES

Air emissions from the flue gas stacks are the only significant emissions from electricity generation and industrial gas turbines and reciprocating engines.

The evaluation of emissions data has indicated that the existing emissions data base was adequate for gas-fueled turbines and reciprocating engines. For distillate oil-fueled gas turbines, the existing data base for NO_x, total hydrocarbons, CO, particulate, SO_2 and SO_3 emissions was adequate. However, the existing data base for trace elements and specific organic emissions is inadequate. For distillate oil reciprocating engines, the existing data base for NO_x, total hydrocarbons, CO, and SO_2 emissions was adequate. The existing

data base for particulates, SO_3, trace elements and specific organic emissions was found to be inadequate.

4.3 EXTERNAL COMBUSTION SOURCES FOR ELECTRICITY GENERATION

For flue gas emissions, the status of the existing data base can be summarized as follows:

- The existing data base for criteria pollutants was generally adequate.
- For sulfuric acid emissions, the existing data base was adequate for bituminous coal-fired boilers, residual oil-fired boilers, and gas-fired boilers, and inadequate for lignite-fired boilers. For emissions of primary sulfates,* the existing data base was adequate for pulverized bituminous dry bottom and wet bottom boilers, residual oil-fired boilers, gas-fired boilers, and inadequate for other combustion source categories.
- For emissions of particulates by size fraction and trace elements, the existing data base was adequate for gas-fired boilers and inadequate for all other combustion source categories.
- For emissions of specific organics and polycyclic organic matter (POM), the existing data base was inadequate for all combustion source categories.

Two other sources of air emissions of environmental concern are cooling tower emissions and emissions from coal storage piles. The existing data bases characterizing air emissions from these two sources were considered to be inadequate, because past studies were primarily focused on the measurements of a limited number of chemical constituents and total particulates. Emissions from ash handling and storage and fuel handling are not addressed here because characterization of these emissions is outside the scope of this study.

For wastewater effluents from external combustion sources for electricity generation, the existing data base was considered to be adequate for wastewater from water treatment processes, and inadequate for all other streams. This is because past studies were limited to the characterization of gross parameters such as pH and total suspended solids (TSS) and a few inorganic constituents. Organic characterization data were generally not available.

*Primary sulfate refers to the sum total of SO_3, expressed as sulfate, metallic sulfates, and ammonium sulfate.

The evaluation of existing emissions data for solid wastes indicated the inadequacy of the organic data base for coal fly ash and bottom ash, and the inadequacy of the inorganic and organic data bases for FGD sludges. On the other hand, the inorganic data base for coal ash was considered to be adequate because of the adequate characterization of the inorganic content of coal. Similarly, the data base for water treatment wastes was considered to be adequate because the waste constituents are inorganic and can be estimated from the raw water constituents and the treatment method used.

4.4 COMMERCIAL/INSTITUTIONAL COMBUSTION SOURCES

Gaseous and particulate emissions from the flue gas stacks are emphasized in the study of commercial/institutional combustion sources. Although some of the larger institutional external combustion systems are local sources of water pollution and fugitive particulate emissions from coal pile storage and ash disposal, their contribution to the national water pollution and fugitive emission burden is negligible. It is estimated, based on the amount of coal consumed by the commercial/institutional sector, that they contribute less than 1 percent of such emissions from all stationary combustion sources.

Evaluation of existing emissions data has indicated that the data base for gas- and oil-fired external combustion sources, although limited, was adequate for NO_x, HC, CO, particulate, and SO_2. However, the existing data base for specific organic emissions for these sources was inadequate, and, for the oil-fired sources, the existing data base for SO_3 and trace elements was inadequate. Emissions data from solid fuel-fired sources were generally inadequate for all pollutants.

In the case of oil-fired internal combustion sources, data were inadequate for SO_3, trace element, and specific organic emissions. Data for gas-fired reciprocating engines are adequate; however, one unit was tested in this program to confirm data adequacy.

4.5 INDUSTRIAL COMBUSTION SOURCES

As in the case of commercial/institutional sources, gaseous and particulate emissions from the flue gas stacks are emphasized in the study of industrial sources. The status of the existing data base for these emissions can be summarized as follows:

- The existing data base for criteria pollutants was generally adequate, with the exception of emissions from wood-fired combustion sources.
- The existing data base for particulate sulfate and sulfuric acid emissions was inadequate for the oil- and solid fuel-fired combustion source categories.
- The existing data base for particulates by size fractions and trace elements was adequate only for gas-fired sources.
- The existing data base for specific organics was inadequate for all industrial source categories.

As noted previously, industrial boilers are also sources of water pollution and solid waste. However, these sources, particularly in the case of large industrial boilers used for electricity generation, are similar to those at electric utilities. These sources of pollution were characterized for electric utilities earlier in this project.

5. THE SOURCE MEASUREMENT PROGRAM

Because of the deficiencies in the existing emissions data base, source tests were conducted at a selected number of sites for each of the five principal combustion source categories. These source tests are described in the following sections.

5.1 GAS- AND OIL-FIRED RESIDENTIAL HEATING SOURCES

Five gas-fired and five oil-fired residential sources were initially selected for testing. The choice of specific sites within the two source categories was based on the representativeness of the sites with respect to such important system characteristics as burner type and age, firing rate, and heating medium (hot air, hot water, and steam). Upon review of the results obtained from the testing of the 10 sites, one gas-fired and two oil-fired systems were subsequently tested to study the effect of cycle mode on organic emissions. Level II analyses for SO_2, SO_3, and particulate sulfate were also conducted at the two oil-fired sites.

5.2 INTERNAL COMBUSTION SOURCES

Eleven internal combustion sites were selected for testing to provide a better characterization of the emissions associated with these sources. The sites tested included one gas-fueled gas turbine, five distillate oil-fueled gas turbines, and five distillate oil reciprocating engines (diesel engines). A gas-fueled gas turbine site was included to assure that previously unidentified pollutants are not being emitted in environmentally unacceptable quantities. Specific sites were chosen based on the representativeness of the sites as measured against the important characteristics of systems within each source category, including engine model, rated capacity, age and pollution control method.

Test results from the first phase were evaluated to determine the need for and type of additional sampling and analysis. These evaluations led to the recommendation of additional tests to determine SO_3 and organic emissions

from electricity generation distillate oil reciprocating engines. Level II tests were subsequently conducted at three of the diesel engine sites previously tested.

5.3 EXTERNAL COMBUSTION SOURCES FOR ELECTRICITY GENERATION

Forty-six sites were selected for sampling and analysis of flue gas emissions, and six sites were selected for sampling and analysis of air emissions from cooling towers. The forty-six sites selected for flue gas sampling and analysis include: three pulverized dry bottom, seven pulverized wet bottom, six cyclone, and three stoker bituminous coal-fired boilers; three pulverized dry bottom, two cyclone, and two spreader stoker lignite-fired boilers; four tangentially-fired and eight wall-fired boilers fueled with residual oil; and three tangentially-fired and five wall-fired boilers fueled with natural gas.

At a selected number of these sites, wastewater streams and solid wastes were also sampled and analyzed. Wastewater streams sampled and analyzed included cooling tower blowdown, once-through cooling water, boiler blowdown, fly ash pond overflow, bottom ash pond overflow, and combined ash pond overflow. Intermittent wastewater streams such as chemical cleaning wastes and coal pile runoff were not sampled. Solid waste streams sampled and analyzed included fly ash, bottom ash, and FGD scrubber sludge.

In addition to the modified Level I tests, comprehensive Level II tests were also conducted for a bituminous coal-fired cyclone boiler, two bituminous coal-fired pulverized dry bottom boilers, and an oil-fired boiler. All these coal-fired boilers were equipped with flue gas desulfurization (FGD) systems. The oil-fired boiler tested used off-stoichiometric firing and flue gas recirculation for NO_x control.

Because direct measurements of chemical constituents present in cooling tower exhausts have not been made except for a limited number of trace elements, six cooling towers were selected for testing in this project. Cooling tower streams sampled and analyzed included air emissions as evaporation and drift, and blowdown.

5.4 COMMERCIAL/INSTITUTIONAL COMBUSTION SOURCES

Twenty-two external combustion systems were tested. These include: five gas-fired, three distillate oil-fired, five residual oil-fired, three anthracite stokers, three bituminous stokers, two bituminous pulverized dry units, and one wood-fired stoker. Four oil-fired, one gas-fired, and one dual-fired internal combustion reciprocating engines were also tested. Specific sites were chosen based on the representativeness of the sites as determined by the important system characteristics within each source category, including system design, size, and age. Many of the sites tested fall within the commercial size classification range, although some, particularly the pulverized bituminous-fired units, greatly exceed the upper commercial size limit of 13.2 GJ/hr input capacity.

5.5 INDUSTRIAL COMBUSTION SOURCES

Twenty-two external combustion systems were tested. These include: ten gas-fired, three distillate oil-fired, and five residual oil-fired boilers; three bituminous pulverized wet bottom and two bituminous pulverized dry bottom units; three bituminous stokers; and five wood-fired stokers. Specific sites were chosen based on the representativeness of the sites as measured against the important system characteristics within each source category, including system design, size, and age.

6. SAMPLING AND ANALYSIS

6.1 LEVEL I FIELD TESTING

The Source Assessment Sampling System (SASS) train, developed by EPA, was used to collect both vapor and particulate emissions in quantities sufficient for the wide range of analyses needed to adequately characterize emissions from external combustion sources. Briefly, the SASS train (Figure 1) consists of a conventional heated probe, three cyclones and a filter in a heated over which collect four particulate size fractions (>10μm, 3-10μm, 1-3μm, <1μm); a gas conditioning system; an XAD-2 polymer adsorbent trap to collect organics and some inorganics; and impingers to collect the remaining gaseous inorganics and trace elements. The train is run until at least 30 m^3 of gas has been collected.

In addition to using the SASS train for stack gas sampling, other equipment was employed to collect those components that could not be analyzed from the train samples. A gas chromatograph (GC) with flame ionization detection was used in the field to analyze hydrocarbons in the boiling point range of -160 to 90°C(reported as C_1 - C_6) collected in gas sampling bags. Additionally, these samples were analyzed for CO, CO_2, O_2, and SO_2 by GC using a thermal conductivity detector. Detailed procedures for sampling and analysis are described in the Methods and Procedures Manual for Sampling and Analysis prepared for this project (15).

Water samples were generally taken by either tap sampling or dipper sampling. Tap samples were obtained on contained liquids in motion or static liquids in tanks or drums. This sampling method was generally applicable to cooling tower blowdown or boiler blowdown. The method involved the fitting of the valve or stopcock used for sample removal with a length of pre-cleaned Teflon tubing long enough to reach the bottom of the container. The dipper sampling procedure, applicable to sampling ponds or open discharge streams, was used in the acquisition of ash pond discharge samples. The method involved the use of dipper with a flared bowl and attached handle, long enough

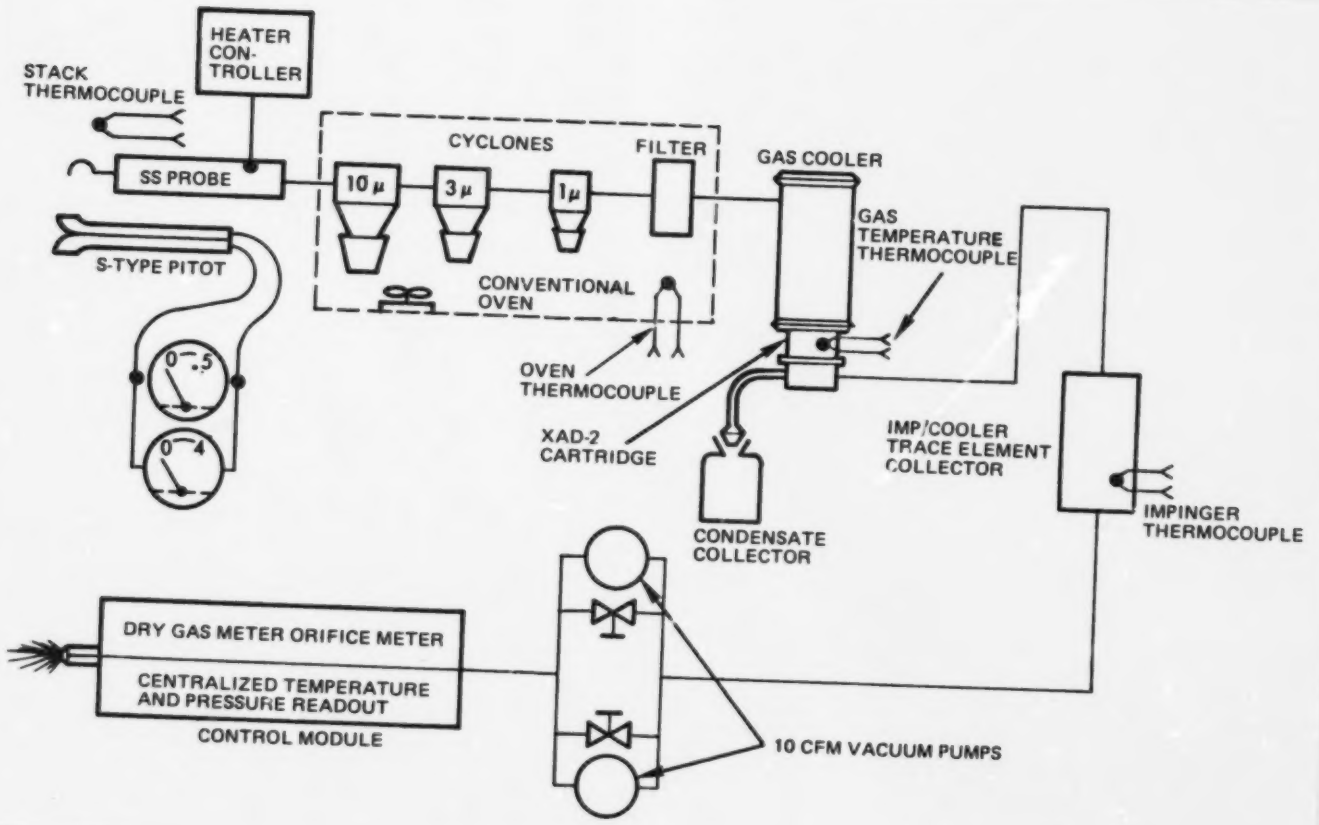

Figure 1. Schematic of Source Assessment Sampling System (SASS)

to reach discharge areas. After sample recovery, water analyses using the Hach kit were performed in the field to determine pH, conductivity, total suspended solids (TSS), hardness, alkalinity or acidity, ammonia nitrogen, cyanide, nitrate nitrogen, phosphate, sulfite and sulfate.

For solids sampling, the fractional shovel grab samples procedure was used unless the plant had an automatic sampling system. The concept of fractional shoveling involves the acquisition of a time-integrated grab sample representative of overall process input or output during a given run time period. A standard square-edged shovel, 12 inches wide, was used. For streams entering or exiting a process operation, a full cross-stream cut sample was taken from the belt on an hourly basis. Each hourly shovel sample was added to a pile to eventually form a run time period composite. At the conclusion of the run, this pile was coned and quartered to form a final representative sample weighing from 2.3 to 4.5 kilograms. When plants were equipped with automatic samplers to remove representative cross sections of a stream while automatically forming a homogeneous composite, these were used in preference to the shovel technique.

In addition to the above sampling methods, sampling for air emissions from cooling towers was performed using a modified EPA Method 5 train without the filter assembly.

6.2 MODIFIED LEVEL I LABORATORY ANALYSIS

The basic Level I schematic outlining flow of samples and analysis plans for particulate and gaseous emissions is depicted in Figure 2. The corresponding schematic for solid, slurry, and liquid samples is presented in Figure 3. These schematics provide a general idea on the apportionment of samples for analysis. For example, it is shown in Figure 2 that the probe and cyclone rinses combination will only be subjected to inorganic analysis if the dried sample exceeds 10 percent of the total cyclone and filter sample weight. Details of the sample handling, transfer, and analysis procedures can be found in the IERL-RTP Procedures Manual: Level I Environmental Assessment (2). A brief description of inorganic and organic analyses performed and the deviations from the basic Level I procedure follows.

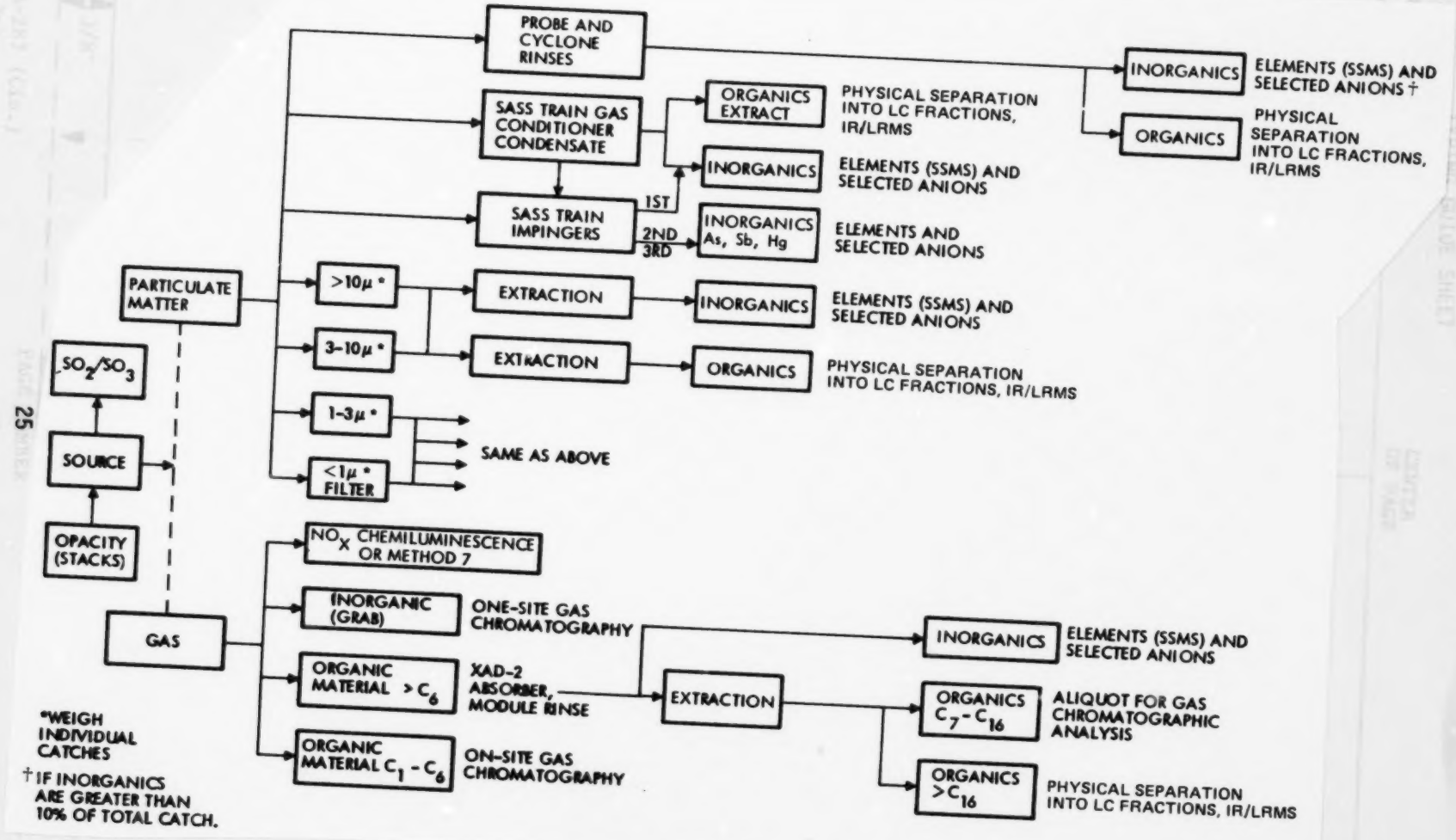

Figure 2. Basic Level 1 Sampling Flow and Analytical Plan for Particulates and Gases

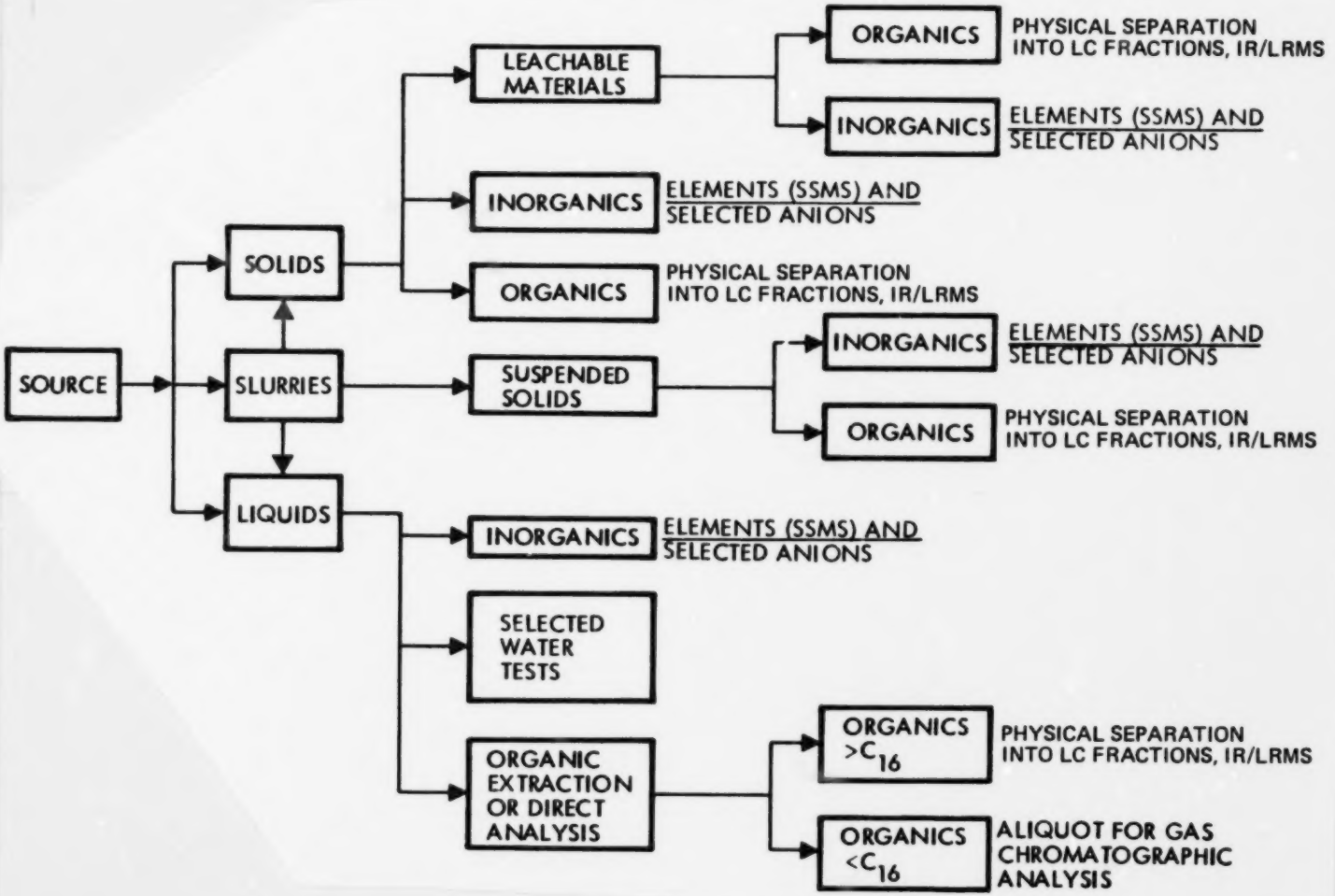

Figure 3. Basic Level 1 Sampling Flow and Analytical Scheme for Solids, Slurries and Liquids

6.2.1 Inorganic Analyses

Level I analysis was used for all inorganic analyses. It was designed to identify all elemental species in the SASS train fractions and to provide semiquantitative data on the elemental distributions and total emission factors. The primary tool for Level I inorganic analysis is the Spark Source Mass Spectrometry (SSMS). SSMS data were supplemented with Atomic Absorption Spectrometry (AAS) data for Hg, As, and Sb and with specific ion electrode determinations for chlorides.

The following SASS train fractions were analyzed for their elemental composition: 1) the particulate filter, 2) the XAD-2 sorbent, and 3) a composite sample containing portions of the XAD-2 module condensate and HNO_3 rinse, and the first impinger solution. Analyses of the carbon, hydrogen, nitrogen, oxygen, and trace element contents and heating values of the fuel were also performed for the coal-fired and oil-fired sources.

6.2.2 Organic Analyses

Level I organic analyses provides data on volatile (boiling point range of 90 to 300°C, corresponding to the boiling points of C_7 - C_{16} n-alkanes and reported as C_7 - C_{16}) and non-volatile organic compounds (boiling point >300°C, corresponding to the boiling points of $>C_{16}$ n-alkanes and reported as $>C_{16}$) to supplement data for gaseous organics (boiling point range of -160 to 90°C, corresponding to the boiling points of C_1 - C_6 n-alkanes and reported as C_1 - C_6) measured in the field. Organics in the XAD-2 module condensate trap and XAD-2 resin were recovered by methylene chloride extraction. SASS train components including the tubing were carefully cleaned with methylene chloride or methylene chloride/methanol solvent to recover all organics collected in the SASS train.

Because all samples are too dilute to detect organic compounds by the majority of instrumental techniques employed, the first step in the analysis was to concentrate the sample fractions from as much as 1000 ml to 10 ml in a Kuderna-Danish apparatus in which rinse solvent is evaporated while the organics of interest are retained*. Kuderna-Danish concentrates were then evaluated by gas chromatography (GC), infared spectrometry (IR), liquid chromatography (LC), and gravimetric analysis, low resolution mass spectroscopy

*Kuderna-Danish is a glass apparatus for evaporating bulk amounts of solvents.

(LRMS), and sequential gas chromatography/mass spectrometry (GC/MS)†. The extent of the organic analysis is determined by the stack gas concentrations found for total organics (volatile and non-volatile). If the total organics indicate a stack gas concentration below 500 $\mu g/m^3$, a liquid concentration below 0.1 mg/l, or a solid concentration below 1 mg/kg, further analysis is not conducted. If the concentrations are above these levels, a class fractionation by liquid chromatography is conducted followed by GC and IR analyses. Additionally, if the concentrations in a LC fraction are above these levels, LRMS is conducted for that particular LC fraction.

6.3 LEVEL II SAMPLING AND ANALYSIS

In addition to the modified Level I tests, Level II tests were also conducted at a selected number of sites. Level II sampling and analysis techniques that have been employed for these sites included:

- Continuous monitoring of NO_x emissions by chemiluminescent instrumentation.
- Continuous monitoring of SO_2 emissions by pulsed fluorescent analyzer.
- Determination of sulfate emissions by the Goksoyr-Ross Controlled Condensation System.
- Determination of particle size distribution by Polarized Light Microscopy (PLM) and MRI cascade impactor.
- Determination of trace element concentrations by Atomic Absorption Spectroscopy (AAS) and Inductively Coupled Plasma Optical Emission Spectroscopy (ICP).
- Identification of inorganic compounds from specific infared band correlations by Fourier Transform IR (FTIR).
- Identification of crystalline material in solid samples by X-ray Diffraction (XRD).
- Determination of the surface and sub-surface sulfur concentrations and oxidation state of bulk samples by Electron Spectroscopy for Chemical Analysis (ESCA).
- Determination of the surface and sub-surface composition of bulk samples by Secondary Ion Mass Spectrometry (SIMS).
- Determination of elemental composition of single particles by Scanning Electron Microscope with Energy Dispersive X-ray Fluroescence (SEM-EDX).

†The major modification in the Level I sampling and analysis procedure was the addition of GC/MS analysis for POM.

- Identification and quantification of non-POM organic compounds by GC/MS.

Detailed discussions of these techniques and their applications could be found in the group/categorty reports (3, 4, 5, 6, 7) and the following environmental assessment and source test and evaluation reports:

- Environmental Assessment of Coal-and Oil-firing in a Controlled Industrial Boiler (16).
- Environmental Assessment of a Coal-fired Controlled Utility Boiler (17).
- Environmental Assessment of an Oil-fired Controlled Utility Boiler (18).
- Source Test and Evaluation Report: Dean H. Mitchell Unit No. 11, Northern Indiana Public Service Co. (19).
- Source Test and Evaluation Report: Cane Run Unit No. 6, Louisville Gas and Electric Co. (20).

7. RESULTS

7.1 GAS-AND OIL-FIRED RESIDENTIAL HEATING SOURCES

The results of the field measurement program along with supplementary values for certain pollutants obtained from the existing data base are summarized in Table 2. Ambient severity factors, defined as the ratio to an ambient air quality level or hazard factor, are also listed in Table 2. The hazard factor for noncriteria pollutants is a reduced threshold limit value (TLV), while for criteria pollutants it is the ambient air quality standard. The TLV is reduced by a factor of 300 (24/8 x 100) to account for length of exposure (24 hrs vs 8 hrs) and an added safety factor of 100 due to the higher susceptibility of the general population to exposure effects. A severity factor of greater than 0.05 is indicative of a potential problem requiring further attention. The "greater than 0.05" criterion reflects an uncertainity factor of 20 in the calculation of ambient severity, because of potential errors introduced in the application of the dispersion model, and in Level I sampling and analysis.

Severity factors calculated from emission data acquired in this project or, in the case of pollutants not measured in this project, from EPA (AP-42) emission factors (21) are shown for a single source and for multiple sources. Maximum ground level concentrations for multiple sources were determined using a dispersion model for an array of 1000 sources. The model assumes a Class C stability (slightly unstable) and a windspeed of 4.5 m/sec (10 mph). Using a grid of houses 80 x 80 m and the average stack parameters found in this study, the maximum ground level concentrations determined by the model were about 25 times greater than those from a single source. As shown in Table 2, multiple source severity factors for several pollutants (NO_x for gas-fired sources and NO_x , SO_3, and Ni for oil-fired sources) exceed 0.05, a value which indicates that emissions are potentially significant.

Data for POM obtained by GC/MS are not reported in the table. POM was not found in the emissions from gas-fired residential sources; the concentrations of POM measured for oil-fired sources were at least two orders of mag-

TABLE 2. SUMMARY OF RESULTS OF EMISSIONS ASSESSMENT FOR RESIDENTIAL SOURCES

Pollutant	Gas-fired Sources			Oil-fired Sources		
	Emission Factor (ng/J)	Ambient Severity Factor	Multiple Source Severity Factor	Emission Factor (ng/J)	Ambient Severity Factor	Multiple Source Severity Factor
NO_x	33	2.8×10^{-3}	7.0×10^{-2}	55	6.2×10^{-3}	1.6×10^{-1}
Total Hydrocarbons	2.6	1.0×10^{-4}	2.5×10^{-3}	9.2	5.3×10^{-4}	1.3×10^{-2}
CO	8.4	1.6×10^{-6}	4.0×10^{-5}	15	4.2×10^{-6}	1.1×10^{-4}
Particulate	1.0	1.7×10^{-5}	4.3×10^{-4}	3.1	7.7×10^{-5}	1.9×10^{-3}
SO_2*	0.26	3.2×10^{-6}	8.0×10^{-5}	106	1.9×10^{-3}	4.8×10^{-2}
SO_3	ND	ND	ND	5.9	1.6×10^{-2}	4.0×10^{-1}
Trace Elements†						
Lead	-	-	-	7.5×10^{-2}	1.0×10^{-3}	17×10^{-3}
Cadmium	-	-	-	2.2×10^{-2}	1.0×10^{-3}	23×10^{-3}
Copper	-	-	-	0.25	2.4×10^{-3}	12×10^{-3}
Nickel	-	-	-	0.49	10×10^{-3}	250×10^{-3}
Chromium	-	-	-	5.5×10^{-2}	1.0×10^{-3}	25×10^{-3}
Organics						
Total Volatile (C_1-C_{16})	1.7	NA	NA	7.7	NA	NA
Total Nonvolatile (>C_{16})	0.8	NA	NA	1.5	NA	NA

* Based on fuel sulfur content of 3.2 ppmv (2000 grains/10^6 ft^3) for gas and 0.25 weight percent for oil.

† Multiple source severity factors for all elements dashed (-) or not listed were less than 0.01. Upper bound values of emissions were used to calculate severity for oil-fired sources.

ND - No Data.

NA - Not applicable. Seventy factors for C_1-C_{16} and >C_{16} organics were not computed because there is no representative TLV for either group.

nitude below levels that are considered hazardous. Compounds considered particularly hazardous, such as benzo(a)pyrene and dibenz(a,h)anthracene, were not found above the detection limit of 0.05 $\mu g/m^3$.

In contrast with earlier studies, a change in the on/off cyclic mode of burner operation from a 50 minute on/10 minute off cycle to a 10 minute on/20 minute off cycle did not result in increased hydrocarbon (or POM) emissions.

7.2 INTERNAL COMBUSTION SOURCES

The results of the field measurement program along with supplementary values for certain pollutants obtained from the existing data base are summarized in Tables 3 and 4.

Tables 3 and 4 also list ambient severity factors, defined as the ratio of the calculated maximum ground level concentrations of the pollutant species to the level at which a potential environmental hazard exists. As can be seen from Tables 3 and 4, the most significant pollutant from internal combustion turbines and reciprocating engines is nitrogen oxides. For reciprocating engines, emissions of total hydrocarbons are also significant, especially in the case of gas-fueled engines. Ambient severity factors for SO_2 emissions from diesel engines, and for SO_3 emissions (in the form of sulfuric acid vapor and aerosols) from oil-fueled gas turbines and reciprocating engines are all greater than 0.05, indicating the environmental significance of emissions of sulfur species.

Trace element emissions from the gas-fueled gas turbine tested were insignificant. For oil-fueled gas turbines and reciprocating engines, sodium, calcium, nickel, copper, iron, zinc, silicon were the trace elements emitted in the largest quantities. Nickel, copper and phosphorus were found to be the only trace elements with severity factors greater than 0.05.

Data for polycyclic organic matter (POM) emissions obtained by GS/MS are not reported in the summary tables. POM was not detected in the emissions from the one gas fueled gas turbine and the five distillate oil-fueled gas turbines tested. POM emissions from the five diesel engines tested were found to be mostly naphthalenes and substituted naphthalenes. Emissions of these organic species resulted in calculated ambient severity factors which were all

TABLE 3. SUMMARY OF RESULTS OF EMISSIONS ASSESSMENT FOR GAS-FUELED INTERNAL COMBUSTION SOURCES

Pollutant	Gas-Fueled Gas Turbines				Gas Reciprocating Engines			
	Elec. Gen.		Industrial		Elec. Gen.		Industrial	
	Emission Factor (ng/J)	Ambient Severity Factor	Emission Factor (ng/J)	Ambient Severity Factor	Emission Factor (ng/J)	Ambient Severity Factor	Emission Factor (ng/J)	Ambient Severity Factor
NO_x	168	0.17	130	0.52	1549	7.1	1549	5.7
Total Hydrocarbons*	23.2	0.020	8.6	0.025	528	1.7	528	1.3
CO	64.8	0.0003	48.8	0.0007	340	0.0051	340	0.0040
Particulate	5.1	0.0019	5.1	0.0062	5.7	0.0068	5.7	0.0055
SO_2	0.26	<0.0001	0.26	<0.0001	0.26	0.0002	0.26	0.0002

*One single data point indicates that 90% of the organics emitted from gas-fueled gas turbines are volatile (C_1-C_{16}) and only 10% are nonvolatile (>C_{16}).

TABLE 4. SUMMARY OF RESULTS OF EMISSIONS ASSESSMENT FOR OIL-FUELED INTERNAL COMBUSTION SOURCES

Pollutant	Distillate Oil-Fueled Gas Turbines				Distillate Oil Reciprocating Engines			
	Elec. Gen.		Industrial		Elec. Gen.		Industrial	
	Emission Factor (ng/J)	Ambient Severity Factor	Emission Factor (ng/J)	Ambient Severity Factor	Emission Factor (ng/J)	Ambient Severity Factor	Emission Factor (ng/J)	Ambient Severity Factor
NO_x	311	0.32	207	0.83	1392	6.4	1392	5.1
Total Hydrocarbons	17.5	0.015	3.6	0.010	52	0.16	52	0.13
CO	43.8	0.0002	101	0.0014	266	0.0040	266	0.0032
Particulate	13.0	0.0049	13.0	0.016	14.1	0.019	14.1	0.015
SO_2	33.1	0.0089	33.1	0.029	101	0.097	101	0.077
SO_3	1.5	0.056	1.5	0.18	1.8	0.23	1.8	0.18
Trace Elements								
Copper	0.58	0.085	0.58	0.28	0.45	0.23	0.45	0.20
Nickel	0.53	0.16	0.53	0.51	0.56	0.60	0.56	0.48
Phosphorus	0.13	0.037	0.13	0.12	0.097	0.10	0.097	0.082
Organics								
Total Volatile (C_1-C_{16})	12.1	NA	ND	NA	18	NA	ND	NA
Total Nonvolatile (>C_{16})	5.4	NA	ND	NA	34	NA	ND	NA

ND- No Data

NA - Not Applicable. Severity factors for C_1-C_{16} and >C_{16} organics were not computed because there is no representative TLV for either group.

well below 0.05. Again, POM compounds known to be carcinogenic were not found above the detection limit of 0.05 $\mu g/m^3$.

7.3 EXTERNAL COMBUSTION SOURCES FOR ELECTRICITY GENERATION

Air Emissions

The results of the field measurement program for flue gas emissions from utility boilers, along with supplementary values for certain pollutants obtained from the existing data base, are presented in Tables 5, 6, and 7. Also listed in these tables are ambient source severity factors, defined as the ratio of the calculated maximum ground level concentrations of the pollutant species to the level at which a potential environmental hazard exists.

As can be seen from Tables 5, 6, and 7 the major criteria pollutants of concern are nitrogen oxides from all combustion source categories, and sulfur dioxide from all but gas-fired combustion sources. Ambient severity factors are also greater than 0.05 for controlled particulate emissions from bituminous coal-fired and lignite-fired sources, uncontrolled particulate emissions from residual oil-fired sources, and total hydrocarbon emissions from bituminous coal-fired boilers, lignite-fired pulverized dry bottom and cyclone boilers, residual oil and gas tangentially-fired boilers, indicating the environmental significance of the emissions of these pollutants. Emissions of carbon monoxide from utility boilers do not appear to be a problem. Additionally, ambient severity factors for emissions of SO_3 (in the form of sulfuric acid vapor and aerosols) and particulate sulfate from all coal-fired and oil-fired utility boilers are greater than 0.05. The environemental problems associated with emissions of nitrogen oxides, sulfur dioxide, and particulate from utility boilers are well known. On December 23, 1971, EPA issued the original New Source Performance Standards (NSPS) to limit emissions of these pollutants from power plants. The Clean Air Act Amendments, enacted August 7, 1977, required EPA to reivse its 1971 standards for power plants to reflect advances in control technology. On June 11, 1979, EPA promulgated the revised NSPS to further limit emissions of nitrogen oxides, sulfur dioxide, and particulate matter from power plants.

TABLE 5. SUMMARY OF ASSESSMENT RESULTS FOR FLUE GAS EMISSIONS FROM BITUMINOUS COAL-FIRED UTILITY BOILERS

Pollutant	Pulverized Dry Bottom		Pulverized Wet Bottom		Cyclone		Stokers	
	Emission Factor (ng/J)	Ambient Severity Factor	Emission Factor (ng/J)	Ambient Severity Factor	Emission Factor (ng/J)	Ambient Severity Factor	Emission Factor (ng/J)	Ambient Severity Factor
NO_x	259*, 379†	1.95*, 2.85†	380	1.70	678	6.36	241	0.13
Total Hydrocarbons	4.5	0.027	4.5	0.016	9.5	0.072	11	0.0048
CO	17	0.0005	86	0.0015	82	0.0030	157	0.0003
Particulates (Controlled)	251	0.66	213	0.33	57	0.19	603	0.12
SO_2 (Uncontrolled)	1,407	2.64	1,407	1.57	1,407	3.29	1,407	0.19
SO_3	13.9	3.50	13.9	2.09	14.1	4.45	13.9	0.26
Particulate Sulfate (Controlled)	0.72	0.15	2.9	0.37	10.8	2.84	10.5	0.16
Trace Elements‡								
Aluminum	8.5	0.53	6.9	0.16	1.4	0.071	2.6	0.008
Beryllium	0.0022	0.23	0.0018	0.11	0.00037	0.048	0.0055	0.041
Calcium	5.6	0.12	4.6	0.056	0.95	0.025	2.6	0.004
Chlorine	33.9	1.03	33.9	0.61	33.9	1.28	33.9	0.075
Fluorine	4.1	0.34	4.1	0.20	4.1	0.42	4.1	0.024
Iron	8.4	0.22	6.8	0.11	1.4	0.047	20.9	0.040
Lead	0.039	0.053	0.031	0.026	0.0066	0.011	0.61	0.061
Lithium	0.024	0.23	0.020	0.11	0.0041	0.048	0.011	0.008
Nickel	0.062	0.13	0.050	0.06	0.011	0.027	1.4	0.211
Phosphorus	0.11	0.22	0.086	0.11	0.018	0.046	0.55	0.083
Silicon	15.2	0.31	12.4	0.15	2.6	0.066	8.7	0.013
POM								
Dibenz(a,h)anthracene	0.00022	0.50	BD	NA	BD	NA	BD	NA
Benzo(a)pyrene/Benzo(e)pyrene	BD	NA	0.0035	21	BD	NA	BD	NA
Total POM	0.0039	NA	0.042	NA	0.0059	NA	0.015	NA
Organics								
Total Volatile (C_1-C_{16})	2.1	NA	3.8	NA	8.3	NA	5.8	NA
Total Nonvolatile (>C_{16})	2.4	NA	0.8	NA	1.2	NA	5.2	NA

BD - Below detection limit. Detection limit for POM was 0.3 $\mu g/m^3$ or approximately 0.001 ng/J.

NA - Not applicable.

*For tangentially-fired pulverized bituminous dry bottom boilers.

†For wall-fired pulverized bituminous dry bottom boilers.

‡For pulverized dry bottom, pulverized wet bottom, and cyclone boilers, the trace element factors presented are for units equipped with electrostatic precipitators. For stokers, the trace element emission factors presented are for units equipped with multiple cyclones.

TABLE 6. SUMMARY OF ASSESSMENT RESULTS FOR FLUE GAS EMISSIONS FROM LIGNITE-FIRED UTILITY BOILERS

Pollutant	Pulverized Dry Bottom		Cyclone		Stokers	
	Emission Factor (ng/J)	Ambient Severity Factor	Emission Factor (ng/J)	Ambient Severity Factor	Emission Factor (ng/J)	Ambient Severity Factor
NO_x	260	4.28	333	5.33	195	0.14
Total Hydrocarbons	9.0	0.12	4.7	0.061	3.2	0.002
CO	33	0.002	33	0.002	65	0.0002
Particulates (Controlled)	62	0.36	132	0.74	615	0.15
SO_2 (Uncontrolled)	628	2.57	628	2.50	628	0.11
SO_3	ND	ND	ND	ND	ND	ND
Particulate Sulfate (Controlled)	0.82	0.38	0.49	0.22	47.6	0.93
Trace Elements*						
Aluminum	0.068	0.006	<0.067	<0.006	15.2	0.056
Barium	<0.025	<0.023	<0.037	<0.032	2.0	0.076
Beryllium	<0.001	<0.23	<0.0003	<0.066	0.0059	0.057
Calcium	0.39	0.017	<1.5	<0.067	< 140	<0.27
Copper	<0.030	<0.068	0.013	0.029	0.083	0.008
Fluorine	0.24	0.044	0.80	0.14	0.42	0.003
Magnesium	<0.22	<0.016	<0.16	<0.011	< 27	<0.085
Nickel	<0.068	<0.31	<0.047	<0.21	0.28	0.053
Phosphorus	<0.034	<0.16	<0.013	<0.055	1.5	0.30
POM						
Biphenyl	BD	NA	0.00002	<0.0001	BD	NA
Trimethyl propenyl naphthalene	0.0033	0.0001	0.00034	<0.0001	0.0032	<0.0001
Organics						
Total Volatile (C_1-C_{16})	7.1	NA	4.1	NA	2.3	NA
Total Nonvolatile (>C_{16})	1.9	NA	0.6	NA	0.9	NA

ND - No data.
BD - Below detection limit. Detection limit for POM was 0.3 $\mu g/m^3$ or approximately 0.0001 ng/J. However, lower detection limits were obtained for less complex samples with fewer interferences or closely eluting GC peaks.
NA - Not applicable.

*For pulverized dry bottom and cyclone boilers, the trace element emission factors presented are for units equipped with electrostatic precipitators. For stokers, the trace element emission factors presented are for units equipped with multiple cyclones.

TABLE 7. SUMMARY OF ASSESSMENT RESULTS FOR FLUE GAS EMISSIONS FROM RESIDUAL OIL- AND GAS-FIRED UTILITY BOILERS

Pollutant	Residual Oil				Natural Gas			
	Tangential Firing		Wall Firing		Tangential Firing		Wall Firing	
	Emission Factor (ng/J)	Ambient Severity Factor	Emission Factor (ng/J)	Ambient Severity Factor	Emission Factor (ng/J)	Ambient Severity Factor	Emission Factor (ng/J)	Ambient Severity Factor
NO_x	114	1.90	190	1.17	124	3.21	233	2.94
Total Hydrocarbons	4.6	0.060	4.6	0.022	2.4	0.047	2.4	0.024
CO	56	0.0035	56	0.0013	33	0.0031	33	0.0015
Particulates	30	0.17	30	0.061	0.25	0.0021	0.25	0.0010
SO_2 (Uncontrolled)	448	1.79	448	0.66	0.25	0.0015	0.25	0.0007
SO_3	13.8	7.43	13.8	2.76	ND	ND	ND	ND
Particulate Sulfate	3.3	1.48	3.3	0.55	ND	ND	ND	ND
Trace Elements								
Beryllium	0.0024	0.52	0.0024	0.19	BD	NA	BD	NA
Chlorine	3.1	0.20	3.1	0.072	2.9	0.29	2.9	0.14
Copper	0.35	0.77	0.35	0.29	0.021	0.069	0.021	0.034
Lead	0.034	0.098	0.034	0.036	BD	NA	BD	NA
Magnesium	2.4	0.18	2.4	0.065	BD	NA	BD	NA
Mercury	0.0015	0.013	0.0015	0.005	0.0049	0.064	0.0049	0.031
Nickel	0.43	1.90	0.43	0.71	0.042	0.28	0.042	0.14
Phosphorus	0.13	0.57	0.13	0.21	0.070	0.46	0.070	0.23
Selenium	0.025	0.056	0.025	0.021	BD	NA	BD	NA
Vanadium	3.7	3.22	3.7	1.19	BD	NA	BD	NA
POM								
Benzopyrenes/ perylenes	6.25×10^{-7}	0.014	6.25×10^{-7}	0.005	BD	NA	BD	NA
Total POM	0.0047	NA	0.0047	NA	BD	NA	BD	NA
Organics								
Total Volatile (C_1-C_{16})	4.2	NA	4.2	NA	2.1	NA	2.1	NA
Total Nonvolatile (>C_{16})	0.4	NA	0.4	NA	0.3	NA	0.3	NA

ND - No data.
BD - Below detection limit. Detection limit for POM was typically 0.3 $\mu g/m^3$ or approximately 0.0001 ng/J. However, lower detection limits were obtained for less complex samples with fewer interferences or closely eluting GC peaks.
NA - Not applicable.

Particulate size distribution data acquired in the current study showed that for bituminous coal-fired utility boilers equipped with electrostatic precipitators, the >10 μm fraction accounted for 1.4 to 82 percent of the total particulate emissions. For lignite-fired utility boilers equipped with multiclones the >10 μm fraction contributed from 50 to 59 percent of the total particulate emissions. An average of less than 15 percent of the particulate emissions from uncontrolled residual oil-fired utility boilers were >10 μm in size.

Trace element data summarized in Tables 5, 6, and 7 are for elements associated with ambient severity factors greater than 0.05 in at least one of the source subcategories (e.g., pulverized dry bottom boilers firing bituminous coal).* Among the trace elements, emissions of beryllium, nickel, and phosphorus appear to be a common concern for bituminous coal-fired, lignite-fired and residual oil-fired sources. An unusual result is that for gas-fired utility boilers, chlorine, copper, mercury, nickel, and phosphorus were found to have ambient severity factors greater than 0.05. The validity of these observations will require confirmation by Level II tests.

Data for polycyclic organic matter (POM) indicated the presence of dibenz(a,h)anthracene in pulverized bituminous dry bottom boilers, and benzo(a)pyrene/benzo(e)pyrene in pulverized wet bottom boilers. Both dibenz(a,h)anthracene and benzo(a)pyrene are active carcinogens. A benzopyrene, possibly benzo(a)pyrene, was also detected at a residual oil-fired site. The only POM compounds detected at lignite-fired sites were biphenyl and trimethyl propenyl naphthalene, neither of which is known to be carcinogenic. No POM was detected at gas-fired utility sites. The detection limit for POM was typically 0.3 $\mu g/m^3$, or approximately 0.1 pg/J.

Air emissions of chlorine, phosphorus, and magnesium from cooling towers are of the same order of magnitude as those from residual oil-fired utility boilers and of environmental concern. Based on thermal energy input to the associated power plants, the mean emission factors for chlorine, phosphorus, and magnesium were determined to be 2.4 ng/J, 0.22 ng/J, and 0.56 ng/J,

*Data for 55 to 60 additional trace elements were available from SSMS analysis.

respectively. The high emission rates for chlorine and phosphorus were due to the use of chlorine and phosphate additives. The high emission rate for magnesium was due to the high solids content in the source of cooling water at one site.

All six cooling towers tested employed sulfuric acid as an additive. Sulfate emissions from these cooling towers ranged from 3 to 41 ng/J. By comparison, controlled sulfate emissions from coal-fired utility boilers and sulfate emissions from oil-fired utility boilers are typically in the 20 to 30 ng/J range.

Wastewater Effluents

The results of sampling and analysis for cooling tower blowdown, boiler blowdown, and ash pond overflow in this program were combined with existing data and summarized in Table 8. Also listed in this table are discharge severities, defined as the ratio of discharge concentration to the health based water Minimum Acute Toxicity Effluent (MATE)* value. A discharge severity greater than 1.0 is indicative of a potential hazard requiring further characterization or development of improved control technology. The "greater than 1.0" criterion instead of the "greater than 0.05" criterion for ambient severity was used because calculation of discharge severities was based on conservative MATE values. Also, the uncertainty in the calculated values only involved potential sampling and analysis errors. The error due to the application of dispersion models was no longer a component.

Other wastewater effluents, including water treatment wastewater, chemical cleaning wastes, FGD wet scrubber wastewater, and coal pile runoff, were not sampled in this project. Characterization data for these wastewater streams, based on results of previous studies reported in the literature, are summarized in Table 9. In both Tables 8 and 9, data for wastewater constituents with discharge severities less than 1.0 are not presented. Also, data for once-through cooling water are not included in Tables 8 and 9, as discharge severities for all constituents in this wastewater stream are extremely low.

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*Also known as Discharge Multimedia Environmental Goal (DMEG). MATE values are given in Reference 22.

TABLE 8. SUMMARY OF ASSESSMENT RESULTS FOR COOLING TOWER BLOWDOWN, BOILER BLOWDOWN, AND ASH POND OVERFLOW

Constituent	Cooling Tower Blowdown		Boiler Blowdown		Fly Ash Pond Overflow		Bottom Ash Pond Overflow		Combined Ash Pond Overflow	
	Effluent Concentration	Discharge Severity	Effluent Concentration	Discharge Severity	Effluent Concentration	Discharge Severity	Effluent Concentration	Discharge Severity	Effluent Concentration	Discharge Severity
Gross Parameters										
pH	7.3	NA	10.5	NA	5.8	NA	7.4	NA	9.2	NA
Conductivity, μmhos/cm	3,050	NA	150	NA	10,000	NA	6,000	NA	480	NA
Hardness, (as $CaCO_3$), mg/l	1,220	NA	340	NA	220	NA	205	NA	185	NA
Alkalinity (as $CaCO_3$), mg/l	56	NA	97	NA	30	NA	62	NA	81	NA
TSS, mg/l	26	NA	87	NA	49	NA	41	NA	33	NA
BOD, mg/l	18	NA	3.0	NA	ND	NA	ND	NA	ND	NA
COD, mg/l	94	NA	53	NA	ND	NA	ND	NA	ND	NA
Trace Elements, mg/l										
Arsenic	0.28	1.1	---	---	8.7	35	2.2	8.9	---	---
Calcium	1,700	0.89	---	---	---	---	---	---	---	---
Cadmium	0.094	1.9	---	---	---	---	---	---	---	---
Chromium	0.48	1.9	---	---	---	---	---	---	---	---
Iron	1.8	1.2	---	---	1.2	0.80	2.5	1.7	---	---
Magnesium	650	1.4	---	---	---	---	410	0.85	---	---
Manganese	0.30	1.2	---	---	0.25	1.0	0.19	0.76	---	---
Nickel	---	---	---	---	0.40	1.8	---	---	---	---
Phosphorus	9.9	6.6	8.0	5.3	---	---	---	---	---	---
Selenium	0.081	1.6	---	---	---	---	---	---	---	---
Silicon	---	---	---	---	---	---	---	---	---	---
Chloride, mg/l	---	---	---	---	---	---	---	---	---	---
Sulfate, mg/l	1,300	1.0	---	---	---	---	---	---	---	---
Phenols, mg/l	---	---	0.026	5.2	---	---	---	---	---	---
Organics, mg/l										
Total volatile (C_7- C_{16})	0.021	NA	1.3	NA	0	NA	0.007	NA	0	NA
Total nonvolatile (>C_{16})	1.41	NA	4.7	NA	0.056	NA	0.090	NA	0.070	NA

ND - No data because analysis for these parameters was not performed.

NA - Not applicable because there are no MATE values associated with these parameters to compute discharge severities.

"---" - Data for constituents with discharge severities less than 1.0 are not presented.

TABLE 9. SUMMARY OF ASSESSMENT RESULTS FOR WATER TREATMENT WASTEWATER, CHEMICAL CLEANING WASTES, WET SCRUBBER WASTEWATER, AND COAL PILE RUNOFF

Constituent	Water Treatment Wastewater				Chemical Cleaning Wastes						Wet Scrubber Wastewater*		Coal Pile Runoff	
	Ion Exchange		Clarification		Acid Phase Composite		Alkaline Phase Composite		Neutralization Drain					
	Effluent Concentration	Discharge Severity	Effluent Concentration	Discharge Severity	Effluent Concentration	Discharge Severity	Effluent Concentration	Discharge Severity	Effluent Concentration	Discharge Severity	Effluent Concentration	Discharge Severity	Effluent Concentration	Discharge Severity
Gross Parameters														
pH	ND	NA	ND	NA	1.1	NA	ND	NA	11.4	NA	7.5	NA	2.7	NA
Hardness (as $CaCO_3$), mg/l	1,000	NA	3,300	NA	ND	NA	ND	NA	ND	NA	ND	NA	ND	NA
Alkalinity (as $CaCO_3$), mg/l	560	NA	340	NA	ND	NA	ND	NA	ND	NA	108	NA	ND	NA
TSS, mg/l	32	NA	25,200	NA	45	NA	67	NA	47	NA	ND	NA	330	NA
BOD, mg/l	36	NA	20	NA	ND	NA	ND	NA	ND	NA	ND	NA	ND	NA
COD, mg/l	48	NA	160	NA	2,870	NA	90	NA	70	NA	185	NA	ND	NA
Trace Elements, mg/l														
Aluminum	---	---	160	1.1	---	---	---	---	---	---	---	---	150	1.0
Beryllium	---	---	---	---	---	---	---	---	---	---	0.04	1.3	0.03	1.0
Chromium	0.27	1.0	0.61	2.4	2.9	12	---	---	---	---	---	---	---	---
Copper	---	---	---	---	15	3.0	530	106	5.1	1.0	---	---	---	---
Iron	4.2	2.8	350	233	2,880	1,920	2.4	1.6	7.3	4.8	---	---	660	440
Lead	---	---	---	---	2.1	8.2	---	---	---	---	---	---	---	---
Magnesium	---	---	---	---	---	---	---	---	---	---	---	---	---	---
Manganese	---	---	---	---	19	77	---	---	---	---	580	1.2	---	---
Mercury	---	---	---	---	---	---	---	---	---	---	0.85	3.4	33	131
Nickel	---	---	---	---	---	---	---	---	---	---	0.044	4.4	---	---
Phosphorus	---	---	---	---	178	809	1.6	7.1	---	---	0.50	2.3	1.5	6.6
Selenium	---	---	0.32	1.5	35	23	143	95	755	503	---	---	---	---
Sodium	---	---	---	---	---	---	---	---	---	---	0.59	12	---	---
Zinc	---	---	---	---	---	---	---	---	0.060	1.3	1,100	1.4	---	---
	3,200	4.0	---	---	---	---	---	---	---	---	---	---	---	---
	---	---	---	---	48	1.9	---	---	---	---	2,500	2.1	---	---
	---	---	---	---	---	---	---	---	---	---	4,700	3.6	---	---
Chloride, mg/l	1,800	1.5	---	---	---	---	---	---	---	---	---	---	---	---
Sulfate, mg/l	---	---	---	---	---	---	2,740	10	0.013	5.7	---	---	---	---
Ammonia, mg/l	---	---	---	---	---	---	---	---	---	---	---	---	---	---
Hydrazine, mg/l	---	---	---	---	---	---	---	---	---	---	---	---	---	---
Phenols, mg/l	---	---	---	---	0.044	8.8	---	---	---	---	---	---	---	---

*Sludge liquor from lime/limestone FGD scrubber.

ND - No data.

NA - Not applicable because there are no MATE values associated with these parameters to compute discharge severities.

"---" - Data for constituents with discharge severities less than 1.0 are not presented.

The summary data presented in Tables 8 and 9 show that cooling tower blowdown, clarification wastewater, chemical cleaning wastes, FGD wet scrubber wastewater, and coal pile runoff all contain a significant number of constituents with discharge severities greater than 1.0. The pollutants of most concern are copper, iron, manganese, nickel, and phosphorus. Based on discharge severities, the boiler blowdown and ash pond overflow streams appear to be less environmentally significant. Of all the wastewater streams investigated, the ash pond overflows are the only streams which have been subjected to treatment by sedimentation. If all the other wastewater streams were also sent to settling ponds before release, their discharge severities should also be considerably lower.

The average organic levels in the wastewater streams sampled were less than 6 mg/l. POM compounds were not found above the detection limit of 2 µg/l.

Solid Wastes

A number of fly ash and bottom ash samples from bituminous coal-fired and lignite-fired utility boilers were acquired and analyzed in this project. The analysis results, supplemented by additional data from the existing literature, are summarized in Table 10. Discharge severities presented in the same table are defined as the ratio of concentration in the solid to the health based solid MATE value. Data for ash trace element constituents with discharge severities less than 1.0 are not presented.

The data on fly ash and bottom ash show that from 11 to 16 of the trace element constituents in ash have discharge severities greater than 1.0. The pollutants of most concern are aluminum, arsenic, calcium, chromium, iron, manganese, nickel, potassium, and silicon. Also, the concentrations of arsenic, barium, boron, calcium, and magnesium in lignite ash appear to be substantially higher than the concentrations of these elements in bituminous coal ash.

Most of the organics in fly ash and bottom ash are present as the $>C_{16}$ fraction. POM compounds were found in only two of the samples above the detection limit of 2 ppm. Even for these two samples, the POM compounds detected were naphthalene, alkyl naphthalenes and other compounds with high MATE values and do not appear to pose a potential hazard.

TABLE 10. SUMMARY OF ASSESSMENT RESULTS FOR FLY ASH AND BOTTOM ASH FROM BITUMINOUS COAL-FIRED AND LIGNITE-FIRED BOILERS

Pollutant	Bituminous Fly Ash		Bituminous Bottom Ash		Lignite Fly Ash		Lignite Bottom Ash	
	Concentration (ppm)	Discharge Severity	Concentration (ppm)	Discharge Severity	Concentration (ppm)	Discharge Severity	Concentration (ppm)	Discharge Severity
Trace Elements								
Aluminum	4,300-100,000	0.27 -6.3	3,700- 90,000	0.23 -5.6	3,500- 35,000	0.22 -2.2	8,100- 27,000	0.51 -1.7
Arsenic	3-240	0.06 -4.8	1- 18	0.02 -0.36	79-830	1.6 - 17	22-400	0.44 -8.0
Barium	280-640	0.28 -0.64	220-450	0.22 -0.45	1,200- 15,000	1.2 - 15	2,100- 20,000	2.1 - 20
Boron	25-700	0.003 -0.075	5.5 -300	0.0006-0.032	320- 13,000	0.034 -1.4	490- 6,300	0.053-0.68
Calcium	1,100-121,000	0.023 -2.5	3,100- 93,000	0.065 -1.9	27,000-130,000	0.56 -2.7	63,000-130,000	1.3 -2.7
Chromium	19-300	0.38 -6.0	15-220	0.30 -4.4	8.1 - 64	0.16 -1.3	5.1 - 22	0.10 -0.44
Cobalt	7- 57	0.047 -0.38	4- 31	0.027 -0.21	7.1 - 1,200	0.047 -8.0	6- 11	0.04 -0.073
Iron	32,000-143,000	110 - 480	47,000-213,000	160 - 710	1,000- 11,000	3.3 - 37	27,000- 71,000	90 - 240
Lead	7-110	0.14 -2.2	6-120	0.12 -2.4	9.3 -160	0.19 -3.2	4.3 -150	0.086-3.0
Lithium	46- 86	0.66 -1.2	3- 60	0.043 -0.86	1.3 - 62	0.019 -0.89	3.8 - 79	0.054-1.1
Magnesium	820- 13,400	0.046 -0.74	1,300- 12,400	0.072 -0.69	17,000- 32,000	0.94 -1.8	4,600- 35,000	0.26 -1.9
Manganese	100-300	2.0 -6.0	37-860	0.74 - 17	200- 1,300	4.0 - 26	310- 1,000	6.2 - 20
Mercury	0.01 - 28	0.0005-1.4	0.1 - 0.5	0.005 -0.025	0.086- 2.0	0.0043-0.1	<0.017- 0.094	<0.001-0.0047
Nickel	10-250	0.22 -5.6	0.3 -100	0.007 -2.2	21- 1,600	0.47 - 36	44-140	0.93 -3.1
Phosphorus	82- 5,100	0.027 -1.7	120- 3,800	0.04 -1.3	120- 4,600	0.04 -1.5	110- 5,200	0.037-1.7
Potassium	2,900- 20,000	0.69 -4.8	1,000- 15,800	0.24 -3.8	1,200- 30,000	0.29 -7.1	660- 15,000	0.16 -3.6
Selenium	4- 32	0.4 -3.2	<1- 5.6	<0.1 -0.56	<2.1 - 19	<0.21 -1.9	1.3 - 5.5	0.13 -0.55
Silicon	17,000-276,000	0.57 -9.2	7,500-276,000	0.25 -9.2	34,000- 53,000	1.1 -1.8	31,000- 50,000	1.0 -1.7
Organics								
Total volatile (C_1-C_{16})	<14- 87	NA	<14- 87	NA	0.5 - 15	NA	0.9 - 11	NA
Total nonvolatile (>C_{16})	0-420	NA	0-900	NA	43-300	NA	150-300	NA

NA - Not applicable. Discharge severities for C_1-C_{16} and >C_{16} organics were not computed because there is no representative MATE value for either group.

Characterization for scrubber sludges in the current study was limited to samples obtained from a single limestone FGD scrubber system. Analyses for the samples indicated that concentrations of ten trace elements in the scrubber sludge exceeded their respective health based solid MATE values. These ten trace elements were: aluminum, arsenic, beryllium, calcium, cadmium, iron, manganese, nickel, lead, and zinc. Organics detected in the scrubber sludge samples were limited to approximately 5 ppm of C_9 and 2 ppm of C_{10}. Further, POM was not detected at the 2 ppm level.

7.4 COMMERCIAL/INSTITUTIONAL COMBUSTION SOURCES

The results of the field measurement program for flue gas emissions from commercial/institutional sources, along with supplementary values obtained from the existing data base for certain pollutants, are presented in Table 11. Also listed in this table are ambient source severity factors, defined as the ratio of the calculated maximum ground level concentration of the pollutant species to the level at which a potential environmental hazard exists.

The emission factors shown in Table 11 are uncontrolled emission factors. However, in the case of the solid fuel-fired combustion categories, some degree of particulate control does exist in the commercial/institutional sector. Overall particulate control efficiency is estimated to be 40 percent for bituminous, pulverized dry bottom boilers and 20 percent for all stokers. Gas- and oil-fired units are essentially uncontrolled. Control measures for other criteria pollutants are not used by commercial/institutional combustion sources.

As can be seen from Table 11, the criteria pollutants of concern are particulates from all uncontrolled solid fuel-fired combustion sources, NO_x from all source categories with the exception of wood-fired stokers, SO_2 from residual oil- and coal-fired sources, and total hydrocarbons from bituminous- and wood-fired stokers and internal combustion reciprocating engines. Ambient severity factors are all greater than 0.05 for these pollutant/source combinations. Emissions of CO from all combustion source categories do not appear to represent an environmental problem. Emissions of particulate sulfate and SO_3 from the solid fuel-fired combustion sources tested do appear to represent a problem since ambient severity factors exceed 0.05.

TABLE 11. SUMMARY OF RESULTS OF EMISSIONS ASSESSMENT FOR COMMERCIAL/INSTITUTIONAL COMBUSTION SOURCES

Pollutant*	Combustion Source Category									
	Gas-fired Boilers		Distillate Oil-fired Boilers		Residual Oil-fired Boilers		Bituminous, Pulverized Dry Bottom		Bituminous Stokers†	
	Emission Factor (ng/J)	Ambient Severity Factor‡	Emission Factor (ng/J)	Ambient Severity Factor	Emission Factor (ng/J)	Ambient Severity Factor	Emission Factor (ng/J)	Ambient Severity Factor	Emission Factor (ng/J)	Ambient Severity Factor
NO_x	50	0.08	68	0.11	172	0.28	352	1.2	117	0.19
Total Hydrocarbons	3	0.0026	3	0.0026	3	0.0026	6	0.01	59	0.05
CO	8	<0.0001	8	<0.0001	8	<0.0001	20	0.0002	195	0.0008
Particulates	2	0.0007	6	0.0022	37	0.014	3,406	2.6	1,075	0.43
SO_2	0.26	<0.0001	106	0.028	464	0.12	766	0.42	766	0.2
SO_3	ND	ND	ND	ND	ND	ND	1.0	0.07	12.2	0.44
Particulate Sulfate**	ND	ND	ND	ND	0.03	0.001	2.1	0.12	3.5	0.10
Trace Elements										
Al	ND	ND	0.015	<0.0001	0.156	0.009	27.5	0.323	8.7	0.048
Ba	ND	ND	0.0084	0.0005	0.0095	0.0006	4.24	0.517	1.33	0.077
Be	ND	ND	0.00004	0.0005	0.00007	0.0009	0.132	4.026	0.04	0.62
Ca	ND	ND	0.845	0.0056	0.780	0.0050	40.7	0.497	12.8	0.074
Co	ND	ND	0.0023	0.0013	0.023	0.0133	0.430	0.534	0.14	0.079
Cr	ND	ND	0.036	0.0104	0.050	0.0144	0.825	0.563	0.26	0.084
Cu	ND	ND	0.205	0.0059	0.093	0.0028	0.605	0.037	0.19	0.006
F	ND	ND	0.014	<0.0001	0.085	0.0003	3.245	0.079	1.02	0.012
Fe	ND	ND	0.545	0.0032	0.379	0.0022	16.5	0.201	5.21	0.030
K	ND	ND	0.060	0.0009	0.213	0.0031	10.5	0.320	3.31	0.048
Li	ND	ND	0.0015	0.0020	0.001	0.0013	1.155	3.203	0.36	0.477
Na	ND	ND	0.101	<0.0001	0.418	0.0022	20.35	0.248	0.42	0.036
Ni	ND	ND	0.112	0.0324	0.804	0.236	1.045	0.637	0.33	0.095
P	ND	ND	0.0057	0.0002	0.107	0.0031	4.675	2.852	1.48	0.425
Si	ND	ND	0.173	0.0005	1.610	0.0047	78.0	0.476	24.6	0.071
V	ND	ND	0.030	0.0002	3.66	2.05	1.375	0.167	0.43	0.025
Total POM	0.010	NA	0.020	NA	0.044	NA	0.002	NA	0.5	NA
Organics										
Total Volatile (C_1-C_{16})	2.4	NA	1.3	NA	2.2	NA	4.4	NA	26	NA
Total Nonvolatile (>C_{16})	0.6	NA	1.7	NA	0.8	NA	1.6	NA	33	NA

- Continued -

TABLE 11 (Continued)

Pollutant*	Combustion Source Category							
	Anthracite Stokers		Wood Stokers		Gas-fired Reciprocating Engines		Oil-fired Reciprocating Engines	
	Emission Factor (ng/J)	Ambient Severity Factor‡	Emission Factor (ng/J)	Ambient Severity Factor	Emission Factor (ng/J)	Ambient Severity Factor	Emission Factor (ng/J)	Ambient Severity Factor
NO_x	145	0.24	10	0.017	1,390	1.66	1,420	1.7
Total Hydrocarbons	5	0.004	100	0.09	400	0.25	300	0.18
CO	15	<0.0001	100	0.0004	300	0.0009	400	0.001
Particulates	145	0.05	215	0.08	5	0.001	40	0.01
SO_2	314	0.08	65	0.017	0.26	0.0001	97	0.017
SO_3	19.3	0.07	ND	ND	ND	ND	ND	ND
Particulate Sulfate**	27.2	0.78	3.5	0.10	ND	ND	ND	ND
Trace Elements								
Al	29.5	0.163	0.031	<0.001	ND	ND	0.288	0.001
Ba	0.278	0.016	0.010	<0.001	ND	ND	0.011	<0.001
Be	0.005	0.072	ND	ND	ND	ND	ND	ND
Ca	0.872	0.005	0.627	0.004	ND	ND	0.107	<0.001
Co	0.028	0.016	0.001	<0.001	ND	ND	0.0005	<0.001
Cr	0.376	0.109	0.004	0.002	ND	ND	0.006	0.001
Cu	0.175	0.005	0.004	<0.001	ND	ND	0.174	0.004
F	0.270	0.003	0.015	<0.001	ND	ND	ND	ND
Fe	6.00	0.034	0.205	0.001	ND	ND	0.110	<0.001
K	2.856	0.041	1.48	0.021	ND	ND	0.144	0.001
Li	0.070	0.104	0.001	0.001	ND	ND	0.0003	<0.001
Na	0.825	0.005	0.024	<0.001	ND	ND	0.091	<0.001
Ni	0.355	0.102	0.004	0.001	ND	ND	0.020	0.004
P	2.11	0.578	0.137	0.039	ND	ND	0.016	0.003
Si	33.8	0.098	1.03	0.003	ND	ND	0.945	0.002
V	0.170	0.010	0.0002	<0.001	ND	ND	0.004	<0.001
Total POM	0.003	NA	26	NA	ND	NA	0.430	NA
Organics								
Total Volatile (C_1-C_{16})	1.9	NA	43	NA	364	NA	206	NA
Total Nonvolatile (>C_{16})	3.1	NA	57	NA	36	NA	94	NA

ND - No data. NA - Not applicable.

* Uncontrolled emissions.

† Emission factors for criteria pollutants adjusted to reflect a capacity weighted distribution of stoker types.

‡ Ambient severity factor is defined as the ratio of the calculated maximum ground level concentration of the pollutant species to the level at which a potential environmental hazard exists. A value greater than 0.05 indicates a potential problem.

** Determined turbimetrically following hot water extraction of sulfate from the collected particulate.

The trace element data shown in Table 11 indicate that many trace elements emitted by uncontrolled fossil fuel-fired combustion sources are of concern. Chlorine emissions, although not shown in the table, should also be of concern for residual oil and coal burning sources based on the chlorine content of these fuels. Ambient source severity factors are generally greatest for bituminous, pulverized dry bottom boilers because of the larger capacity of these units. However, ambient severity factors exceed 0.05 for many trace elements emitted by the smaller stoker-fired units. Elements of greatest concern appear to be aluminum, barium, beryllium, chromium, lithium, nickel, phosphorus and silicon. In addition, emissions of nickel from distillate oil sources, and nickel, chromium, and vanadium from residual oil sources are significant. Ambient severity factors based on the upper limit emission factor exceed 0.05. Information found in the existing data base would also indicate that ambient severity factors can exceed 0.05 for chlorine, cobalt, and magnesium emissions from residual oil combustion. Because many commercial/institutional fossil fuel-fired sources are totally uncontrolled or only partially controlled, further consideration of trace element emissions from these sources appears warranted.

POM emissions from some of the commercial/institutional sources tested are of significance. Of most concern were POM emissions from an underfeed stoker unit burning wood fuel during one test and bituminous coal during a second test. POM emission factors were extremely high for these tests, 15,000 and 26,000 pg/J, respectively, for coal and wood combustion. In addition, at least one active carcinogen, dibenz(a,h)anthracene, was identified, and the presence of other carcinogens, e.g., benzo(a)pyrene and benzo(g,h,i)perylene, was indicated. Level II analysis is needed to provide positive identification of the POM compounds emitted by this stoker. It should be noted that this unit was operated at low heat input levels during both test periods. This operating condition would result in lower furnace temperatures and probably inefficient combustion, factors that would favor formation of POM compounds. Emissions of POM compounds from all other external combustion sources were not significant; levels were low (0 to 50 pg/J) and the compounds identified were primarily naphthalene and its derivatives.

POM emissions from the oil-fired (and dual-fired) reciprocating engines were relatively high, in the range of 100 to 800 pg/J. However, these emission levels were similar to those found in the existing data base for oil-fired engines, and ambient severity factors did not exceed 0.05 for any of the compounds detected. The high POM emissions measured for the dual-fired engine were somewhat surprising because the quantity of oil used represented only 5 percent of the total thermal input. No POM emissions were detected from the engine fired solely by gas.

7.5 INDUSTRIAL COMBUSTION SOURCES

The results of the field measurement program for flue gas emissions from industrial sources, along with supplementary values obtained from the existing data base for certain pollutants, are presented in Table 12. Results of analyses of ash samples from wood-fired systems are also presented in the table. Also listed in Table 12 are ambient source severity factors, defined as the ratio of the calculated maximum ground-level concentration of the pollutant species to the level at which a potential environmental hazard exists. For the ash samples collected during tests of the wood-fired sources, discharge severity, the ratio of the elemental concentration in the ash to the health MATE value of the element, was used as a measure of potential hazard. A discharge severity exceeding one is considered to warrant concern regarding the impact of emissions on health.

The particulate, elemental, and particulate sulfate emission factors shown in Table 12 are the mean values of those measured in this study. One bituminous, pulverized wet bottom unit and one bituminous stoker were controlled by electrostatic precipitators. Multiclones were used on the remaining bituminous coal-fired units, with the exception of one pulverized dry unit, which was controlled by a double alkali flue gas desulfurization (FGD) unit (measured particulate efficiency - 99.47 percent). Two wood-fired boilers were controlled by particulate scrubbers; the remaining three wood-fired units were uncontrolled. Emission factors for gas- and oil-fired units presented in the table represent uncontrolled emission factors. As noted previously, the overall efficiency of particulate control in the industrial sector is 81 percent for pulverized units and 53 percent for stokers. Gas- and oil-fired

TABLE 12. SUMMARY OF RESULTS OF EMISSIONS ASSESSMENT FOR INDUSTRIAL COMBUSTION SOURCES

Pollutant	Combustion Source Category									
	Gas-fired Boilers		Distillate Oil-fired Boilers		Residual Oil-fired Boilers		Coal-fired Bituminous Pulverized Dry Bottom Boilers		Coal-fired Bituminous Pulverized Wet Bottom Boilers*	
	Emission Factor* (ng/J)	Ambient Severity Factor†	Emission Factor* (ng/J)	Ambient Severity Factor†	Emission Factor* (ng/J)	Ambient Severity Factor†	Emission Factor* (ng/J)	Ambient Severity Factor†	Emission Factor* (ng/J)	Ambient Severity Factor†
NO_x	70	0.35	70	0.35	170	0.85	350	1.8	586	2.9
Total Hydrocarbons	1	<0.01	3	0.01	3	0.01	6	0.02	6	0.02
CO	8	<0.01	15	<0.01	15	<0.01	20	<0.01	20	<0.01
Particulates	2	<0.01	6	<0.01	30	0.05	12	0.02	20	0.03
SO_2	0.26	<0.01	106	0.11	464	0.52	766	0.85	766	0.85
SO_3	ND	ND	ND	ND	5.7	0.87	4.1	0.60	ND	ND
Particulate Sulfates	ND	ND	ND	ND	ND	ND	1.8	0.15	0.12	3.2
Trace Elements										
Al	ND	ND	180	<0.01	175	<0.01	930	0.02	1100	0.03
As	ND	ND	4	<0.01	<1	<0.01	50	0.12	14	0.03
Ba	ND	ND	1	<0.01	<1	<0.01	21	<0.01	70	0.02
Be	ND	ND	1	<0.01	<1	0.01	<1	0.03	<1	<0.01
Ca	ND	ND	75	<0.01	228	<0.01	70	<0.01	400	<0.01
Cd	ND	ND	1	<0.01	<1	<0.01	<1	<0.01	<1	<0.01
Co	ND	ND	4	0.01	11	0.03	20	0.05	6	0.01
Cr	ND	ND	24	0.06	29	0.07	28	0.07	5	0.01
Cu	ND	ND	38	<0.01	10	<0.01	22	<0.01	19	<0.01
Fe	ND	ND	380	0.01	55	<0.01	660	0.02	1400	0.03
K	ND	ND	85	<0.01	260	0.01	160	<0.01	200	0.01
Li	ND	ND	<1	<0.01	<1	0.01	<1	<0.01	<1	<0.01
Mn	ND	ND	42	<0.01	8	<0.01	62	<0.01	6	<0.01
Na	ND	ND	62	<0.01	1235	0.06	240	0.01	974	0.05
Ni	ND	ND	255	0.32	730	0.89	15	0.02	16	0.01
P	ND	ND	46	0.05	18	0.02	28	0.03	89	0.11
Pb	ND	ND	24	0.02	1	<0.01	6	<0.01	88	0.11
Si	ND	ND	725	<0.01	5790	0.07	1350	0.02	713	<0.01
V	ND	ND	195	0.05	365	0.09	15	<0.01	5	<0.01
Total POM	ND	ND	0.015	NA	<0.001	NA	90	NA	0.003	NA
Organics										
Total Volatile (C_1-C_{16})	0.9	NA	1.5	NA	2.8	NA	5.3	NA	5.6	NA
Total Nonvolatile (>C_{16})	0.1	NA	1.5	NA	0.2	NA	0.7	NA	0.4	NA

-Continued-

TABLE 12 (Continued)

Pollutant	Combustion Source Category									
	Coal-fired Bituminous Stokers		Wood-fired Boilers		Ash from Wood Combustion					
					Bottom Ash		Cinder Ash		Scrubber Ash	
	Emission Factor* (ng/J)	Ambient Severity Factor†	Emission Factor* (ng/J)	Ambient Severity Factor†	Concentration (ppm)	Discharge Severity**	Concentration (ppm)	Discharge Severity**	Concentration (ppm)	Discharge Severity**
NO_x	290	1.1	50	0.25	ND	ND	ND	ND	ND	ND
Total Hydrocarbons	20	0.05	100	0.36	ND	ND	ND	ND	ND	ND
CO	40	<0.01	400	<0.01	ND	ND	ND	ND	ND	ND
Particulates	84	0.1	70	0.11	ND	ND	ND	ND	ND	ND
SO_2	766	0.64	65	0.07	ND	ND	ND	ND	ND	ND
SO_3	ND	ND	ND	ND	ND	ND	ND	ND	ND	ND
Particulate Sulfate‡	4.5	0.38	3.1	0.35	ND	ND	ND	ND	ND	ND
Trace Elements										
Al	890	0.02	577	0.01	11,270	0.70	9,700	0.61	8,900	0.56
As	144	0.35	12	0.03	10	0.19	7	1.4	18	0.36
Ba	66	0.02	90	0.21	1,640	1.6	2,800	28	560	0.56
Be	2.8	0.13	<1	0.01	<1	0.06	<1	0.01	<1	0.08
Ca	820	<0.01	14,280	1.8	119,000	2.5	416,670	8.7	110,000	2.3
Cd	<1	<0.01	3	<0.01	<1	0.03	1	0.10	<1	<0.01
Co	34	0.08	<1	<0.01	17	0.12	15	0.10	20	0.15
Cr	58	0.14	6	0.015	2,300	46	28	0.55	260	5.2
Cu	270	0.03	106	0.01	129	0.13	280	0.28	90	0.09
Fe	2,660	0.06	876	0.02	32,670	109	47,030	157	22,000	73
K	1,370	0.08	18,750	1.1	28,530	6.8	38,330	9.1	14,000	3.3
Li	13	0.07	3	0.03	6	0.08	5	0.08	7	0.10
Mn	37	<0.01	314	<0.01	9,230	185	4,900	98	5,000	112
Na	990	0.05	66	<0.01	4,330	0.03	12,100	0.08	4,200	0.03
Ni	184	0.22	29	0.04	185	4.1	94	2.1	140	3.1
P	810	1.0	1,190	1.5	9,770	3.3	5,620	1.9	6,200	2.1
Pb	127	0.10	50	0.04	23	0.46	52	1.0	30	0.60
Si	1,875	0.02	750	<0.01	91,330	3.0	140,670	4.7	75,000	2.5
V	54	0.01	5	<0.01	69	0.14	72	0.14	65	0.13
Total POM	0.18	NA	0.18	NA	BD	NA	BD	NA	NA	NA
Organics										
Total Volatile (C_1-C_{16})	19	NA	46	NA	6	NA	37	NA	16	NA
Total Nonvolatile (>C_{16})	1	NA	54	NA	6	NA	97	NA	19	NA

* Controlled emissions of particulates, particulate sulfate, and trace elements.

† Ambient severity is defined as the ratio of the calculated maximum ground level concentration to the level at which a potential hazard exists. A value equal to or greater than 0.05 is considered significant.

‡ Determined turbimetrically following hot water extraction of sulfate from the collected particulate.

** Discharge severity is defined as the ratio of the concentration in the ash to the health MATE value of the pollutant. A value equal to or greater than 1.0 is considered significant.

BD - Below detection limit. ND - No data. NA - Not applicable.

units are essentially uncontrolled. Control measures for criteria pollutants other than particulates are not widespread in the industrial sector.

As can be seen from Table 12, the major criteria pollutants of concern are: particulates from residual oil sources and all uncontrolled solid-fuel-fired units; NO_x from all source categories; SO_2 from oil- and solid-fuel-fired sources, including wood-fired units for which the ambient severity factor exceeds 0.05 for those burning wood with a sulfur content of 0.1 percent; and total hydrocarbons from bituminous stokers and wood-fired boilers. Ambient source severity factors are all greater than 0.05 for these pollutant/source combinations. Emissions of CO from all the combustion source categories tested do not represent an environmental problem.

Particulate sulfate and SO_3 emissions from the solid fuel-fired sources tested are associated with ambient source severity factors in excess of 0.05 and, thus, represent a potential environmental hazard. Also, SO_3 emissions, measured in one test of a unit burning residual oil, are significant despite the use of a double alkali FGD unit to control emissions from this source. Although the SO_2 removal efficiency of this FGD unit was 97.5 percent, only 28.5 percent of the SO_3 was removed from the flue gas.

The trace element data shown in Table 12 indicated that many trace elements emitted by controlled bituminous coal-fired sources are of concern. Elements of greatest concern appear to be arsenic, beryllium, cobalt, chromium, iron, potassium, lithium, sodium, nickel, phosphorus, lead, and silicon. Chlorine, on the basis of its concentration in coal, and other elements, in addition to those listed above, may also be of concern because of variations in the elemental content of bituminous coals. Because many industrial sources are totally uncontrolled or only partially controlled, further consideration of the emission of trace elements are warranted.

Trace element emissions of concern from the wood-fired sources tested include barium, calcium, potassium, and phosphorus. Ambient source severity factors calculated from the mean of the emission factor from these sources exceed 0.05 for these elements. Overall removal efficiency of particulates and nonvolatile trace elements from the five wood-fired units tested is estimated to be 36 percent.

Chromium, nickel, phosphorus, and vanadium emissions from distillate oil-fired sources, and chromium, sodium, nickel, silicon, and vanadium emissions from residual oil-fired sources are significant. Ambient severity factors, based on mean emission factors measured in this study, exceed 0.05. In addition, information in the existing data base indicates that ambient severity factors can exceed 0.05 for chlorine, cobalt, fluorine and magnesium emissions from residual oil-fired boilers.

POM emissions from bituminous stokers and wood-fired boilers are potentially significant. Mean emission factors for total POM were 180 and 210 pg/J, respectively, for these sources. Although no active carcinogens were positively identified and ambient severity factors for most compounds were less than 0.05, the possible presence of benzo(a)pyrene in significant amounts was indicated in the emissions of two wood-fired boilers and one bituminous stoker. Level II testing is needed to provide positive identification of the POM compounds emitted from these sources.

The samples of ash collected from the wood-fired sources were analyzed for trace elements by SSMS and for organics, total chromatographic organics (TCO), gravimetric organics, and POM. Three types of samples were collected; bottom ash, cinder ash collected downstream of the combustion chamber, and fly ash collected by a particulate scrubber control device. Discharge severity, the ratio of the elemental concentration in the ash to the elemental health MATE value for solids, was used to evaluate the impact of ash disposal. A value in excess of one indicates that a potential environmental problem exists.

As shown in Table 12, the discharge severity is in excess of one for several trace elements. Elements of concern in bottom ash are barium, calcium, chromium, iron, potassium, manganese, nickel, phosphorus, and silicon. For cinder ash, discharge severities in excess of one were found for arsenic, barium, calcium, iron, potassium, manganese, nickel, phosphorus, and silicon. Fly ash elements of concern include calcium, chromium, iron, potassium, manganese, nickel, phosphorus, and silicon. If ecological effects are considered, several other elements will warrant concern because the ecology MATE values are generally lower than those for health.

As anticipated, volatile and gravimetric organics were not present in significant amounts in bottom ash. Organics were generally found in greater amounts in cinder ash and fly ash, but are not of environmental concern. Although POM compounds were not found in the samples of bottom ash and cinder ash, they were found in the one sample of fly ash collected by a particulate scrubber. The POM compounds were identical to POM compounds collected downstream of the scrubber by the SASS train at this site. Further, the relative distribution of these compounds in the scrubber ash and in the SASS samples was similar. Based on this, wood fly ash will present a definite hazard at sites emitting POM compounds such as benzo(a)pyrene. The compound benzo(a)pyrene was tentatively identified in the flue gas emissions of two uncontrolled wood-fired boilers during this study.

8. CONCLUSIONS

Evaluation of the results from the field tests and the emission data from the existing data base has led to a number of significant conclusions. These conclusions are presented in the sections which follow.

8.1 GAS- AND OIL-FIRED RESIDENTIAL HEATING SOURCES

Based on the use of multiple source severity factor, emissions of NO_x from gas-fired sources and NO_x, SO_3 and Ni from oil-fired sources have been identified as environmentally significant. Emissions of trace elements from gas-fired sources and trace elements other than Ni from oil-fired sources, on the other hand, are not of environmental concern. Additionally, no POM was detected from gas-fired sources. Multiple source severity factors for POM emissions from oil-fired sources are generally two to five orders of magnitude below levels considered hazardous.

In terms of contributions to the nationwide emissions burden, emissions of particulates, SO_2 and NO_x from gas-and oil-fired residential sources account for about 0.2, 0.9 and 2.5 percent, respectively, of emissions from all stationary sources. Emissions of CO from residential sources account for about 0.5 percent of the total CO emissions from stationary sources, with gas- and oil-fired sources contributing equally. Hydrocarbon emissions from residential sources account for about 0.2 percent of the total hydrocarbon emissions from stationary sources, with oil-fired sources contributing 62 percent of the gas- and oil-fired residential total.

The average emissions factors for criteria pollutants measured in this project, despite large source-to-source variations, are in good agreement with EPA AP-42 emissions factor. A singular exception is the hydrocarbon emission factor for oil-fired sources which is 3.1 times greater than the corresponding EPA emission factor. However, the multiple source severity factor for hydrocarbon emissions from oil-fired sources is only 0.013, indicating the insignificance of this pollutant from residential sources.

The SO_3 emission factor for oil-fired sources measured in this project

is three times greater than the corresponding EPA emission factor. Since SO_3 emissions from oil-fired residential sources have been identified as a potential problem, it is recommended to conduct further work to determine SO_3 emission factors from these sources.

Additional work to characterize emissions is also recommended in two other areas because of data uncertainity. First, although POM emissions were determined for the sources tested in this study, the data base is still sparse and additional sampling and analysis efforts to determine emission factors for POM should be undertaken. Second, within the accuracy limitations of Level I ($\pm$ a factor of three), a change in burner cycle mode in the operation of oil-fired sources from 50 minutes on/10 minutes off to 10 minutes on/20 minutes off had no effect on hydrocarbon and POM emissions. This result is not consistent with the effect of cycle on emissions noted in other studies and merits further investigation.

8.2 INTERNAL COMBUSTION SOURCES

Emissions of NO_x from stationary internal combustion sources are a potential environmental problem. NO_x emissions from these sources account for approximately 18 percent of the total NO_x emissions from stationary sources. Of the NO_x emissions from internal combustion sources, more than 80 percent are contributed by the industrial reciprocating gas engine category. Ambient severity factors for NO_x emissions from gas turbines and reciprocating engines range from 0.17 to 7.1.

In addition to NO_x emissions, emissions of hydrocarbons from stationary internal combustion sources also contribute significantly to the national emissions burden. These emissions account for approximately 4 percent of the total hydrocarbon emissions from stationary sources. More than 80 percent of the hydrocarbon emissions from internal combustion sources are contributed by the industrial reciprocating gas engine category. Ambient severity factors for hydrocarbon emissions range from 0.01 for industrial gas-fueled gas turbines to 1.7 for industrial reciprocating gas engines.

Emissions of CO, SO_2 and particulates from stationary internal combustion sources contribute only an insignificant fraction of the emissions of these pollutants from stationary sources. Further, ambient severity factors for CO,

SO_2 and particulate emissions are well below 0.05, with the exception of SO_2 emissions from diesel engines. Ambient severity factors for SO_2 emissions from industrial and electricity generation diesel engines are 0.08 and 0.10, respectively.

For distillate oil-fueled gas turbines, an average of 3.8 percent of the sulfur present in the fuel is converted to SO_3. For diesel engines, an average of 1.4 percent of the fuel sulfur is converted to SO_3. The percent of fuel sulfur converted to SO_3 is lower for diesel engines because of the lower oxygen level in reciprocating engines. Ambient severity factors for SO_3 emissions range from 0.05 to 0.23 for oil-fueled internal combustion sources. For distillate oil reciprocating engines, the data base for SO_3 emissions is marginal and could be improved by additional field tests.

Emissions of trace elements from gas-fueled internal combustion sources are negligible when compared with emissions of trace elements from oil-fueled sources. For oil-fueled internal combustion sources, emissions of copper, nickel and phosphorus are associated with ambient severity factors greater than 0.05.

Emissions of individual organic species from stationary internal combustion sources are environmentally insignificant. Analysis results indicated that organic emissions from oil-fueled internal combustion sources consist mainly of saturated and unsaturated aliphatic and aromatic hydrocarbons. The most prevalent organic species present are saturated straight chain and branched hydrocarbons. Substituted benzenes are the second most abundant organic species emitted. Ambient severity factors for these organic emissions are well below 0.05. Additionally, POM emissions from gas- and oil-fueled gas turbines were at levels too low to be differentiated from blank values. For diesel engines, the POM emitted were mostly naphthalenes and substituted naphthalenes, with ambient severity factors well below 0.05. POM compounds known to be carcinogenic, such as benzo(a)pyrene and dibenz(a,h)anthracene, were not found above the detection limit of 0.05 $\mu g/m^3$.

8.3 EXTERNAL COMBUSTION SOURCES FOR ELECTRICITY GENERATION

Characterization of Flue Gas Emissions

External combustion sources for electricity generation are well known as

major contributors of NO_x, SO_2, particulates, and total hydrocarbons to the environment. Emissions of NO_x from these sources account for approximately 50 percent of the total NO_x emissions from all stationary sources. Of the NO_x emissions from external combustion sources for electricity generation, 77 percent are contributed by burning of bituminous coal. Ambient severity factors for NO_x emissions from utility boilers range from 0.13 for bituminous coal-fired stokers to 6.4 for bituminous coal-fired cyclone boilers.

Emissions of SO_2 from external combustion sources for electricity generation contribute significantly to the national emissions burden. These emissions account for approximately 57 percent of the total SO_2 emissions from all stationary sources. Approximately 88 percent of the SO_2 emissions from external combustion sources for electricity generation are contributed by burning of bituminous coal. Ambient severity factors for uncontrolled SO_2 emissions range from 0.0007 for natural gas, wall-fired boilers to 3.3 for bituminous coal-fired cyclone boilers.

As with emissions of NO_x and SO_2, emissions of particulates from external combustion sources for electricity generation, despite the widespread application of control devices, are still significant environmental problems. These emissions account for approximately 25 percent of the total particulate emissions from all stationary sources. Almost all ($\sim$95 percent) particulate emissions from external combustion sources for electricity generation are contributed by burning of bituminous coal. Ambient severity factors for particulate emissions range from 0.001 for natural gas, wall-fired boilers to 0.74 for lignite-fired cyclone boilers.

Emissions of total hydrocarbons from external combustion sources for electricity generation contribute approximately 0.6 percent of the total emissions of these pollutants from all stationary sources. Ambient severity factors for emissions of total hydrocarbons range from 0.005 to 0.12.

Emissions of CO from external combustion sources for electricity generation are not an environmental concern. Ambient severity factors for CO emissions are all well below 0.05. Total CO emissions from these sources account for approximately 4 percent of CO emissions from all stationary sources.

Aside from the criteria pollutants, flue gas emissions of SO_3 (in the form

of sulfuric acid vapor and aerosol) and particulate sulfate from bituminous coal-fired, lignite-fired, and residual oil-fired utility boilers require further attention. Ambient severity factors for known SO_3 emissions range from 0.26 to 7.4. Ambient severity factors for controlled emissions of particulate sulfate range from 0.15 to 0.93. Thus, emissions of both SO_3 and particulate sulfate are environmentally important.

Of the trace elements present in bituminous coal, flue gas emissions of aluminum, beryllium, chlorine, cobalt, chromium, iron, nickel, phosphorus, lead, and silicon from most coal-fired boilers are of environmental significance. For residual oil-fired utility boilers, flue gas emissions of beryllium, chlorine, copper, magnesium,nickel, phosphorus, lead, selenium, and vanadium with ambient severity factors greater than 0.05, warrant special concern. Measurements of flue gas emissions from gas-fired utility boilers indicate that the average emissions of chlorine, copper, mercury, nickel and phosphorus associated with ambient severity factors greater than 0.05. This is a surprising result requiring further characterization studies for confirmation.

Analysis of organic emissions from utility sites indicated that the principal organic constituents in flue gas are glycols, ethers, ketones, and saturated and aliphatic hydrocarbons. The most prevalent species appear to be the glycols and ethers which have MATE values in the range of 10 to 1100 mg/m^3. Ambient severity factors calculated using these MATE values indicated that emissions of specific organics (excluding POM) are probably not of concern with respect to human health.

POM compounds emitted at the highest concentrations in flue gas streams from bituminous coal-fired sources include naphthalene, phenanthrene, and pyrene. Dibenz(a,h)anthracene and possibly benzo(a)pyrene, both active carcinogens, were detected at a limited number of sites at levels of environmental concern. The only POM compounds identified in flue gas emissions from lignite-fired sources were biphenyl and trimethyl propenyl naphthalene. Carcinogenic POM compounds were not detected. For residual oil-fired sources, POM compounds emitted at the highest concentrations in flue gas streams are naphthalene and biphenyl. Again, carcinogenic POM compounds were not detected. No POM was detected in flue gas streams from gas-fired utility boiler sites.

Characteristics of Air Emissions from Cooling Towers

Two potential environmental problems associated with the air emissions from cooling towers have been identified. First, air emissions of chlorine, magnesium and phosphorus from mechanical draft cooling towers with high drift rates are comparable to flue gas emissions of these elements from residual oil-fired utility boilers and of environmental significance. Second, sulfate emissions from mechanical draft cooling towers employing sulfuric acid as an additive, and with design drift losses in the 0.1 to 0.2 percent range, are of the same magnitude as sulfate emissions from coal-fired and oil-fired utility boilers.

Characteristics of Wastewater Discharges

The major sources of wastewater discharges from external combustion sources for electricity generation are: once-through cooling water, blowdown from recirculating cooling systems, wastes from water treatment processes, chemical cleaning wastes, and coal pile runoff. Discharges from once-through cooling system amount to 7,780,000 l/sec and account for approximately 99.8 percent of the total wastewater from conventional utility power plants. Of the remaining sources, blowdown from recirculating cooling systems is the largest contributor to wastewater discharge.

From an environmental standpoint, the pollutants of most concern in wastewater effluents from conventional utility power plants are iron, magnesium, maganese, nickel, and phosphorus. The average organic levels in the ash pond effluents sampled were less than 0.1 mg/l. Average organic levels in the cooling tower blowdown and boiler blowdown sampled were 1.5 mg/l and 6.0 mg/l, respectively. POM compounds were not found above the detection limit of 2 µg/l.

Based on discharge severities, the once-through cooling water and ash pond overflow streams appear to be of lesser environmental significance than the other wastewater streams from conventional fossil-fueled steam electric plants. Total pollutant loading from wastewater streams will, however, depend on individual discharge flow rates.

Characteristics of Solid Wastes

Solid waste streams generated by conventional utility power plants consist primarily of coal ash and sludge from FGD systems. In 1978, total ash product-

ion was 63.6 Tg and total FGD sludge production was 2.1 Tg (on ash-free basis).

Leaching of trace elements from coal ash may result in environmental contamination. Concentrations of 11 to 16 trace elements in bituminous coal ash and lignite ash exceed their health based solid MATE values. The pollutants of most concern are aluminum, arsenic, calcium, chromium, iron, manganese, nickel, potassium, and silicon.

Organics in bituminous coal ash and lignite ash are mostly present as the $>C_{16}$ fraction. POM concentrations in fly ash and bottom ash are not at levels of environmental concern. The only POM compounds detected were naphthalene, alkyl naphthalenes, and other compounds with high MATE values.

Key Data Needs

The combination of emissions data from this measurement program and the existing data base provides adequate characterization of flue gas emissions of criteria pollutants from most external combustion sources for electricity generation. The notable exception is the lack of emissions data for pulverized dry bottom boilers firing Texas Lignite. This is a serious data deficiency because approximately 16,000 MW of added generating capacity are planned for this source category in the 1978-1985 period.

In addition to the general data needs to characterize flue gas emissions from pulverized dry bottom boilers fired with Texas lignite, a number of specific data needs have been identified. These are listed as follows:

- Size distribution data for flue gas emissions of particulates are inadequate for bituminous coal-fired, lignite-fired, and residual oil-fired utility boilers.
- For bituminous coal-fired and residual oil-fired utility boilers, the data base for SO_3 emissions is adequate. However, SO_3 emissions data for lignite-fired sources are presently unavailable.
- The data base for uncontrolled particulate sulfate emissions from residual oil-fired sources is adequate. The data base for controlled particulate sulfate emissions from bituminous coal-fired and lignite-fired sources, however, is inadequate.
- For bituminous coal-fired boilers equipped with electrostatic precipitators, the data base characterizing flue gas emissions is adequate for most trace elements. Similar data bases characterizing flue gas emissions of trace elements from sources equipped with wet scrubbers and mechanical precipitators, however, are inadequate.

- Existing data for flue gas emissions of trace elements from lignite-fired utility boilers are generally not available. Analysis of the data acquired in this program indicated the need for additional characterization studies.

- The data base characterizing flue gas emissions of trace elements from residual oil-fired utility boilers appears to be adequate except for beryllium, calcium, chlorine, copper, fluorine, magnesium, lead, selenium, and vanadium. The emissions data base for these trace elements can be improved by analysis of additional residual oil samples.

- Although current data indicated that flue gas emissions of specific organics (excluding POM) are probably not of concern with respect to human health, more detailed Level II organic analysis would be required to conclusively determine the significance of organic emissions.

- The data base characterizing flue gas emissions of POM from bituminous coal-fired sources is adequate except for dibenz(a,h)anthracene and benzo(a)pyrene. Emissions of these specific POM compounds will require further characterization.

- The data bases characterizing cooling tower blowdown, ash pond overflow, chemical cleaning wastes, wet scrubber wastewater, and coal pile runoff are inadequate. The present study has been instrumental in applying Level I techniques to identification of wastewater constituents which pose potential environmental problems. Since potential problems were detected by Level I techniques, further studies using Level II techniques will be required to adequately characterize wastewater effluents from utility boilers.

- Data on FGD scrubber sludge are limited. Needed data will be provided by extensive scrubber sludge characterization studies currently in progress under the direction of EPA and the Electric Power Research Institute (EPRI).

8.4 COMMERCIAL/INSTITUTIONAL COMBUSTION SOURCES

Flue gas emissions of particulates, NO_x, SO_2, CO and total hydrocarbons from commercial/institutional sources represent approximately 1.7 percent, 5.0 percent, 3.0 percent, 0.5 percent and 0.3 percent, respectively, of total emissions of these pollutants from stationary sources. Despite this relatively minor contribution to national emissions, criteria pollutant emissions from individual combustion sources can have a significant local impact.

Based on calculated ambient severity factors, criteria pollutants and sulfur compounds of environmental concern in flue gas emissions include NO_x from all commercial/institutional sources except wood-fired stokers, SO_2

from coal- and residual oil-fired sources, SO_3 and particulate sulfate from coal-fired sources, particulates from uncontrolled coal- and wood-fired sources, and total hydrocarbons from bituminous stokers, wood stokers, and reciprocating engines. Specifically, particulate emissions from the coal- and wood-fired sources are of particular concern, because moderate-to-high efficiency control devices are required to reduce ambient severity factors to 0.05 and particle size distribution data are presently inadequate. Flue gas emissions of CO, on the other hand, do not appear to be a problem as ambient severity factors for all source categories are 0.001 or less.

Flue gas emissions of trace elements from several source categories are of concern. For uncontrolled coal-fired combustion sources, elements with ambient severity factors in excess of 0.05 include aluminum, barium, beryllium, calcium, chlorine, cobalt, chromium, copper, fluorine, iron, potassium, lithium, sodium, nickel, phosphorus, lead, silicon and vanadium. Emissions of other elements also could be of significance given the variability of the elemental contents of coals. In addition, emissions of nickel from distillate oil combustion sources, as well as nickel, chlorine, chromium, and vanadium from residual oil combustion sources, are also associated with ambient severity factors in excess of 0.05.

Emission levels for POM compounds from gas- and oil-fired commercial/institutional sources are generally low and the compounds that were detected from coal- and wood-fired combustion sources, however, are still inadequate. The effect of heat input levels, on/off operating modes, excess air levels, and other operating parameters on POM emissions need to be studied in more detail. If these factors are found to contribute significantly to POM emissions, studies to determine the prevalence of contributory source operating parameters in the commercial/institutional sector should be undertaken to establish the magnitude of the problem.

8.5 INDUSTRIAL COMBUSTION SOURCES

Flue gas emissions of particulates, NO_x, SO_2, CO and hydrocarbons from industrial external combustion sources represent approximately 9.0 percent 10.1 percent, 5.7 percent, 1.7 percent and 0.4 percent, respectively, of total emissions of these pollutants from stationary sources. With the exception of CO emissions, emissions of all other criteria pollutants are environ-

mentally significant for at least some of the industrial external combustion source categories. The major criteria pollutants of concern are NO_x from all industrial boilers, SO_2 from residual oil- and bituminous coal-fired sources, total hydrocarbons from bituminous coal-fired stokers and wood-fired stokers, and uncontrolled particulates from bituminous coal- and wood-fired sources. Ambient severity factors are highest for NO_x emissions, which range from 0.25 for wood-fired stokers to 2.9 for pulverized bituminous coal-fired wet bottom units.

Ambient source severity factors are also greater than 0.05 for SO_3 emissions from the two source categories tested - pulverized bituminous coal-fired wet bottom boilers and residual oil-fired boilers, and for emissions of particulate sulfate from bituminous coal and wood combustion.

Flue gas emissions of trace elements from controlled bituminous coal-fired boilers are of concern. Bituminous coal-fired stokers, probably because of less efficient control of particulates, were the largest emitters of trace elements and particulates. Elements of principal concern are arsenic, beryllium, chlorine, cobalt, chromium, iron, potassium, lithium, sodium, nickel, phosphorus, and lead. Emissions of trace elements from uncontrolled wood-, distillate oil-, and residual oil-fired boilers are also of concern. Elements with ambient severity factors in excess of 0.05 include barium, calcium, potassium, and phosphorus from wood-fired boilers, chromium, nickel, phosphorus, and vanadium from distillate oil-fired boilers, and chlorine, chromium, sodium, nickel, silicon and vanadium from residual oil-fired boilers.

Analysis of organic emissions from industrial sites indicated that the principal organic constituents are esters, ethers, glycols and aliphatic and aromatic hydrocarbons. The most prevalent constituents are generally associated with MATE values in the 10 to 1000 mg/m^3 range. Ambient severity factors will not exceed 0.05 at these MATE levels.

POM emissions of potential environmental significance may be present in the flue gas emissions from bituminous stokers and wood-fired boilers. A compound, tentatively identified as benzo(a)pyrene, was found at some of these sites. Phenanthrene was also emitted in significant amounts from one of the wood-fired boilers. POM emissions from pulverized bituminous coal-fired wet bottom boilers, oil-fired boilers, and gas-fired are not considered to be a

problem. POM compounds identified in highest concentrations include naphthalene and phenanthrene from pulverized bituminous coal-fired wet bottom boilers, biphenyl from oil-fired boilers, and naphthalene and phenanthrene from gas-fired boilers.

Because of inadequacies in the data base that characterizes emissions, it is recommended that additional studies be conducted to provide the identified data needs. The primary data needs include particle size distribution data and POM data for flue gas emissions from coal- and wood-fired industrial boilers.

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